THE IMPLEMENTATION OF A RISK BASED MAINTENANCE POLICY TO A POWER PLANT

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The Implementation of a Risk Based Maintenance Policy to a Power Plant

By

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Abstract

The unexpected failures, the down time (outage) associated with such failures, the loss of production of power and, the higher maintenance costs are major problems in operation of thermal power plants. The unexpected failure of an equipments and systems causes economic risk and can be minimized using an effective maintenance strategy. The risk based approach ensures a strategy, which is cost effective. Such an approach uses the information obtained from the study of failure modes and their consequences.

The purpose of the thesis is to develop and show how to implement a risk based maintenance (RBM) policy to a power plant. This quantitative approach will provide a basis for selection of the best alternative strategy to minimize the risk resulting from breakdowns or failures.

The proposed methodology is comprised of three modules: risk assessment, risk evaluation, and maintenance planning. This work presents a mechanism for the study of the occurrence of failures and functional failures in equipment and the severity of their consequences, known as risk. Maintenance of equipment is prioritized based on the risk, and the reduction in overall risk of the plant is accomplished by focusing on the maintenance of high-risk items first. To the author's knowledge this quantitative approach has not been developed before.

The study is conducted for Newfoundland and Labrador Hydro, Holyrood thermal power generation plant. Failure data is collected from the existing power station (Unit 3 – 150 MW) over a period of twelve years. The data is modeled using Weibull and Exponential distributions to estimate the parameters. A probabilistic risk analysis is performed to quantify the risk at the plant. An acceptable risk criterion is determined and the major systems and subsystems that are found to have a risk higher than acceptable risk are identified. The maintenance interval is calculated by reverse or target probability analysis for reducing the level or risk resulting from the failure of a system.

To conclude, the risk based maintenance strategy can be employed to prioritize the systems for maintenance planning, and to improve the existing maintenance policies. In addition, this strategy provides cost-effective means for maintenance as well it minimizes the consequences (safety, economic and environment) related to a system failure.

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RBM	Risk based maintenance
PM	Preventive maintenance
RCM	Reliability centered maintenance
HVAC	Heating, ventilating and air-conditioning system
MC	Maintenance cost
PLC	Production lost cost
FTA	Fault tree analysis
PROFAT	Probabilistic fault tree analysis
MW	Mega watt
KV	kilo volt
KVA	kilo volt-ampere
MCR	Maximum continuous rating
R (t)	Reliability function
F (t)	Failure probability distribution
λ (t)	Failure rate or Hazard rate function
DFR	Decreasing failure rate
CFR	Constant failure rate
IFR	Increasing failure rate
MTTF	Mean time to failure
F (t_i)	First order failure time
MTBF	Mean time between failures
POP	Population
MWh	Mega watt-hour
H	Hours
PIT	Pressure Indicating Transmitter

TIT	Temperature Indicating Transmitter
LIT	Level Indicating Transmitter
FIT	Flow Indicating Transmitter
FI	Flow Indicator
FCS	Flow Control System
(n)	Number of valves, reducers in series

Chapter – 1 Introduction

1.1 Maintenance

Industrial activities are generally classified into production and service. In case of production, equipment and labour are used to produce a product, which can be sold at a much higher price than that of the raw material, which was used in making the product. In the later case, equipment and labour are combined to produce a service. Power plants are classified under production. The production activity cannot continue to function unless a profit is made. This requires that the activity must be carried out in the most efficient and economical manner. The equipment used for the production of power will deteriorate if no maintenance is carried out. Maintenance is defined as the combination of activities by which equipment or systems are kept in, or restored to, a state in which it can perform its designated functions.

1.2 Basic Maintenance policies

The maintenance activity is divided into two major categories: replacement and maintenance. The selection of a maintenance policy depends on various factors and varies between types of power plant/industry. The most common maintenance policies are as follows:

1.2.1 Breakdown Maintenance (Run to Failure)

This policy is usually adopted when the component under consideration operates as an individual unit, thus, its failure will not affect the overall performance of the plant or constitute a safety hazard. The cost of preventing its failure may be more than the cost of breakdown. So, under this policy only lubrication and minor servicing and readjustments are performed. Most equipment maintained according to this policy suffers a large number of breakdowns. Many of these breakdowns develop from minor faults. These initial faults develop into more serious conditions because of absence of maintenance.

Usually, breakdown maintenance is an unscheduled maintenance action, basically composed of unpredictable maintenance needs that cannot be preplanned or programmed on the basis of occurrence at a particular time. This policy will make it hard to estimate the size of the maintenance team needed to maintain the equipment because maintenance requirement is random. This policy is used when the cost of the scheduled maintenance of the equipment is more than the cost of letting it run to failure

1.2.2 Preventive maintenance

The preventive maintenance strategy was introduced in 1950's. Preventive maintenance is an important component of maintenance activity. It can be described as the care and servicing by individuals involved with maintenance to keep equipment/facilities in a satisfactory operational state by providing for systematic inspection, detection, and correction of incipient failures either prior to their occurrence or prior to their development into major failure. However, the disadvantages of preventive maintenance are: exposing equipment to possible damage, using a greater number of parts, increase in initial costs, failure in new parts/components, and demands for more frequent access to an equipment (Dhillion, 2003).

1.2.3 Predictive maintenance (Condition monitoring)

Predictive maintenance has emerged from being a technical niche into mainstream and widespread use as a critical element in the management strategy of power plants operating rotating machinery all over the world. The concept of condition monitoring is to select a measurable parameter on the machines, which will change as the health or condition of a machine, or other production asset deteriorates. The parameter is regularly monitored, to any changes. Once, a change is detected, a more detailed analysis of the measurements to determine what the problem is, and hence arrive at a diagnosis of the problem. Examples of parameters that can be monitored are vibration characteristics, temperature, and wear debris content and form. However, the selection of equipment for predictive maintenance based on risk-based results will be more cost-effective.

1.2.4 Reliability Centered Maintenance (RCM)

The origins of RCM can be traced to studies performed in the early 1960's by the commercial airline industry. This research revealed that scheduled overhauls of complex equipment had very little effect on reliability and safety, and that a new concept was needed to address scheduled maintenance. With the introduction of Boeing's 747 aircraft, the airlines recognized that it would be financially impossible to continue prior scheduled maintenance philosophy. Facing this, the airline industry utilized the results of this research to develop MSG (Maintenance Steering Group) Logic. This is a logic methodology for developing scheduled maintenance programs for new aircrafts. MSG Logic continued to evolve into MSG II and drew the interest of the military in the 1970's. At the request of the United States Department of Defense (DoD), United Airlines was commissioned to develop a maintenance strategy based on MSG for the US military. The principles and applications of RCM were documented in Nowlan and Heap's publication, "Reliability-Centered Maintenance"(Office of the assistant secretary of Defense, 1978). This report became the foundation for modern day RCM processes.

In the 1980's, DoD further refined and expanded the RCM process in a series of military standards and handbooks. Others developed similar processes. Through the 80's and 90's a number of these processes began to gain acceptance throughout various industries. Eventually, some of these processes began to diverge from the original tenets of the original Nowlan and Heap concept. Also, in the mid 1990's, DoD, in an effort to streamline its acquisition process, decided to rely more on commercial standards instead of traditional military standards. After reviewing available commercial processes and realizing that there was no "standard" RCM process, DoD asked the Society of Automotive Engineers to develop an RCM standard.

Reliability centered maintenance is a systematic process used to determine what has to be accomplished to ensure that any physical facility is able to continuously meet its designated functions in its current operating context. It provides the means to assess and rank (priority index) the items and equipment that are critical to operational goals within the operational window.

Moreover, RCM, policy can be used to optimize the preventive maintenance by analyzing the constituent items of the systems with regard to the consequences of their failure. It results in increased reliability and operability, as well a reduced overall maintenance cost. But, RCM initiatives involve a tremendous amount of resources, time, and energy. It is usually a long-term goal with a short-term expectation. Recently, risk based maintenance policy started to emerge of the increased awareness of risk in public.

1.3 Need of a Risk Based Maintenance (RBM) Policy

An electrical power plant based on oil-fired technology is a highly complex production system comprising many different machines and types of equipment working under very different operating conditions. Failure of such systems can be catastrophic especially during winter seasons for all people living in Newfoundland and Labrador because of many houses are electrically heated. Generally, in these plants it is necessary to define a mix of different maintenance strategies in order to increase the availability and to reduce the operating costs.

Industries worldwide spend a huge amount of money on maintenance of production machinery. In Canada, five billion dollars are spent because of poor lubrication practices in industries and power plants. Each year U.S industry spends well over $300 billion on plant maintenance and operation, (Dhilion, 2003). Furthermore, it is estimated that approximately 80% of the industry dollars are spent to correct chronic failures of machines, systems and injured people. The elimination of these chronic failures through effective maintenance can reduce cost between 40% to 60%.

Rapid industrialization and, the increased complexity of the machines in power plants in recent years, had led to new expectations. New techniques and new research in maintenance management are being pursued. Since the 1930s the evolution of maintenance can be traced through three generations. For the first generation, between 1940 to 1950, the policy was “fix it when it breaks”. For the second generation, between 1950 to 1970, there was an explosive growth in new maintenance techniques such as scheduled maintenance and the introduction of computers (Moubray, 1991) For the third generation, after 1970's, new techniques were developed including condition monitoring, hazard studies, failure mode and effect analysis, expert systems and Reliability Centered Maintenance.

At the beginning of the twentieth century, the ASME Code (1998) focused principally on performance criteria to improve safety and reduce the frequency of failure, addressing pressure vessel and piping systems in particular. Later, the importance of risk (event probability multiplied by the consequences) was recognized as an important measure of system safety, and it was seen that risk analysis could be applied to design, material selection, defect criteria, fabrication, operation, maintenance and inspection.

The risk of system failure has also attracted the attention of engineers and researchers related to the field of maintenance. In recent years maintenance has become a major issue and several approaches have been developed and implemented. There have been numerous research papers written on reliability and quantitative risk analysis. Recently, Risk based Maintenance started to emerge in maintenance engineering field. Risk-based Maintenance (RBM) is a holistic approach used to improve maintenance management systems, programs, and practices. The key advantage is that RBM integrates risk information into the decision making process. The present study is based on this methodology, and in view with the need of comprehensive and quantitative risk analysis based on available data, this thesis proposes a maintenance policy for an electrical power generating plant, which will be more reliable than current practices.

1.4 Aims and objectives

The aim of this work is to identify, assess and quantify the risk of failure of the equipment in a power plant. The study integrates fault tree modeling and consequence analysis to quantify the risk. The detailed objectives of this study are

- To illustrate how a risk based maintenance policy can be used to reduce the level of risk, caused by failure of critical equipment in a power plant, to an acceptable level.

- To illustrate how to use the developed RBM policy to optimize the maintenance of major systems and subsystems in a power plant.

1.5 Outline of the thesis

The background of the thesis has been presented in the previous sections along with the objectives of the study. The following chapters review the relevant literature as it relates to Risk Based Maintenance (RBM), the concept of risk, introduction to Holyrood power plant, the major components of Unit 3, description of the physical asset, failure data collection and modeling, risk estimation, evaluation and maintenance planning, findings and conclusions and finally recommendations.

The major highlight of this study is the inclusion of functional failures. It has helped to identify the performance of the unit 3 from the bottom line to the maximum capacity. The failure data is collected based on the functional failures and modeled using Weibull exponential distributions to estimate the parameters. The system flow charts are analyzed and all the functional failures are identified from the system functional perspective and in consultation with plant engineers. The acquired information is transformed into graphical representation using the fault tree. This method quantifies the probability of system failure. The consequence models are developed to quantify the economic consequences. The probability of failure multiplied by the consequences gives the risk of system failure. This analysis helps to identify the individual system risk of failure, and provides the basis for the decision makers to choose the correct maintenance policy.

Chapter – 2 Literature Review

In order to fulfill the research objectives outlined in the previous section a detailed review of literature is necessary to highlight the state of the art in this particular area. This chapter summarizes the development and use of risk based maintenance practices, starting from 1992 to 2003.

It is obvious that maintaining equipment and plants is very costly and time-consuming activity. Maintenance is also important to maintain the health and to promote the safety since records show that these activities are closely associated with excessive accidents rates (Rushworth and Masons, 1992).

Veswly, Belhadj, and Rezos (1993) used probabilistic risk assessment as a tool for maintenance prioritization applications. The minimal cutset contribution and the risk reduction importance are the two measures calculated. Using, minimal cutsets or the risk reduction importances, the basic events and their associated maintenances can also be prioritized for their risk level. Moreover, basic events having low risk and unimportant maintenances can also be identified.

A general procedure is presented by Vaurio (1995) for optimizing the test and maintenance intervals of safety related systems and components. The method is based on minimizing the total plant-level cost under the constraint that the total accident frequency (risk) remains below a set criterion. Component failures, common cause failures and human errors are included and modeled by basic events, the probabilities of which are simple functions of test and maintenance intervals. Analytical solutions have been obtained for several risk models, illustrating how different factors influence the optimization.

A methodology for risk-based inspection of pressurized systems was developed by Hagemeijer and Kerkveld (1998). The methodology is based on the determination of risk by evaluating the consequences and the likelihood of equipment failure. Likelihood of equipment failure is assessed, by means of extrapolation, at the future planned maintenance campaign to identify the necessary corrective work. The objective is to optimize the inspection and maintenance efforts in order to minimize the risk in Brunei petroleum plant. The plant operates a large number of aging production and evacuation facilities.

Harnly (1998) developed a risk ranked inspection recommendation procedure that is used by one of Exxon's chemical plants to prioritize repairs that have been identified during equipment inspection. The equipment are prioritized based on the severity index, which is failure potential combined with consequences. The reduction in overall risk of the plant is accomplished by working high-risk items first.

Taking decision concerning a selection of maintenance strategy using risk-based criteria is essential to develop cost effective maintenance polices for mechanized and automated systems because in this approach technical features (such as reliability and maintainability characteristics) are analyzed considering economic and safety consequences (kumar, 1998). This approach provides a holistic view of the various decision scenarios concerning maintenance strategy where cost consequences of every possible solution can be assessed quantitatively. Risk based maintenance strategies can also be used to improve the existing maintenance policies through optimal decision procedures in different phases of the risk cycle of a system.

Unexpected failures usually have adverse effects on the environment and may result in major accidents. Studies by Kletz (1994), Khan and Abbasi (1998), and Kumar (1998) show the close relationship between maintenance practices and the occurrence of major accidents. Profitability is closely related to availability and reliability of the equipment. The major challenge for a maintenance engineer is to implement a maintenance strategy, which maximizes availability and efficiency of the equipment; controls the rate of equipment deterioration; ensures a safe and environmentally friendly operation; and minimizes the total cost of the operation. This can only be achieved by adopting a structured approach to the study of equipment failure and the design of an optimum strategy for inspection and maintenance.

The American Society of mechanical engineers recognized the need of risk-based methods and organized multidisciplinary research task forces on risk based in-service inspection

(ISI) and testing (IST) and formulated polices, codes, standards and guides in the late 1980s. These research groups worked to determine appropriate risk-based methods for developing inspection and testing guidelines for several applications. A series of ASME publications present this work, which includes both nuclear and industrial applications. Balkey, Art and Bosnak (1998) developed a technology, which includes risk based ranking methods, beginning with the use of plant probabilistic risk assessment (PRA), for the determination of risk-significant and less risk-significant components for inspection and the determination of similar populations for pumps and valves for in-service testing. This methodology integrates non-destructive examination data, structural reliability/ risk assessment results, PRA results, failure data and expert opinion. These ASME methods were applied to the maintenance of nuclear power plants.

There has been an increased focus on risk based maintenance optimization in the offshore industry prompted by new functional regulations on risk. Aplend and Aven (1999) presented alternative probabilistic frameworks for this optimization using a Bayesian approach.

Industry, environmental agencies and the scientific community have all emphasized the need to include environmental impact considerations next to profitability objectives on the design phase of modern chemical processes, responding to the increasing social concern over environmental degradation on the past years. Vassiliadis and Pistikopoulas (2000) have developed maintenance-based strategies for environmental risk minimization on the process industries. The work represents the mechanism of occurrence of unexpected events usually related to equipment failures and the severity of their consequences. Detailed processes, reliability and maintenance characteristics are incorporated in the process optimization framework. The best preventive maintenance strategies that accomplish the conflicting environmental problems were developed.

Dey (2001) presented a risk-based model for inspection and maintenance of a cross-country petroleum pipeline that reduces the amount of time spent on inspection. This model not only reduces the cost of maintaining petroleum pipelines, but also suggests efficient design and operation philosophies, construction methodology and logical insurance plans. The risk based model uses analytical hierarchy process (AHP), a multiple attribute decision making technique, to identify the factors that influence failure on specific segments and analyses their effects by determining probability of risk factors. The severity of failure is determined through consequence analysis. From this the effect of failure caused by each risk factor can be established in terms of cost, and the cumulative effect of failure is determined through probability analysis. This method can be used to identify the right pipeline or segment for inspection and maintenance policy, serving the budget allocation for inspection and maintenance, providing guidance to deploy the right mix of labor in inspection and maintenance and enhancing emergency preparations.

The use of a risk-based policy in the maintenance of medical devices has been tackled by Capuano and Koitko (1996) and Ridgway (2001).

Misewicz, Smith, Nessim and Playdon (2002) developed a risk based integrity project ranking approach for Kinder Morgan, Inc natural gas pipelines and CO_2 pipelines. The approach is based on a benefit cost ratio, defined as the expected risk reduction in dollars per mile over the project useful life, divided by the total project cost. Risk reduction is estimated using quantitative risk analysis approach in which the failure rate reduction achieved by carrying out a given project is multiplied by the expected failure costs. The project ranking provides a useful guide for selecting projects that fit within maintenance budget while providing greatest risk reduction. The benefit cost results can also be used as a tool to justify the maintenance budget. Substantial cost savings can be achieved by using this risk-based approach.

Maintenance decisions on risk analysis results were discussed by Backlund and Hannu (2002). An effective use of resources can be achieved by using risk-based maintenance decisions to guideline where and when to perform maintenance. A comparative study based on three independent risk analyses performed on a specific Hydro power plant was discussed. The comparison and evaluation of the analyses reveal major differences in performance and results, along with various factors that affect the quality of the analyses. Based on the study the authors emphasized the need of quantitative risk analysis. Also, the focus when performing risk analysis must be on the functions required of the associated subsystems and equipments.

A holistic, risk based approach to asset integrity management was discussed by Montogomery and Serratella (2002). The approach is referred to as risk based maintenance and is based on proven risk assessment and reliability analysis methodologies, as well as the need to have appropriate management systems. Combining risk assessment techniques and risk based decision-making tools provides operators with the realistic way to achieve corporate and regulators objectives.

The review of literature indicates that there is a new trend to use the level of risk as a criterion to plan maintenance tasks. However, most of the previous studies focused on a particular equipment type. Recently, Khan and Haddara (2003) proposed a new and comprehensive methodology for risk-based maintenance and illustrated the applicability of the same by applying it to a HVAC system. The methodology integrates quantitative risk assessment and evaluation and proven reliability analysis techniques. The equipment are prioritized based on total risk (economic, safety and environmental), finally developing maintenance plan reduces unacceptable risk.

Least-cost strategies for asset management (operation, maintenance and capital expenditures) are essential for increasing the revenues in power plants. The risk-centered approach of this study will help to take decisions on maintenance interval as well, to prioritize the equipments for maintenance. This thesis describes the application of a risk-based maintenance policy for developing planned maintenance guidelines to Holyrood thermal power plant.

Chapter – 3 Risk Based Maintenance

The RBM analysis systematically prioritizes system failure modes based on total risks (business interruption, safety, maintenance cost, etc.) so that planned maintenance resources may be appropriately allocated. This specifies applicable and effective planned maintenance tasks (preventive and predictive) using a task selection guide that promotes consistent and appropriate choices of maintenance tasks and frequencies. Also, produces recommendations for system improvements that reduce and/or eliminate the need for planned maintenance tasks (or otherwise improve reliability). The risk-based maintenance approach uses both the frequency of the failure occurrence and the consequence of the failure to prioritize component failure modes and ultimately to select a set of maintenance tasks based on the risk associated with the potential failure. Usually RBM improves maintenance decisions by appropriately

- Integrating risk information into the decision-making process.
- Focusing the resources on the highest-risk equipment failures that can lead to system failures.
- Reducing maintenance costs by: (1) systematically determining/optimizing the facilities planned maintenance activities (2) identifying critical spares and optimizing maintenance stores inventories.
- Providing means to evaluate alternative inspection and test strategies.
- Providing means for prioritizing corrective maintenance activities.
- Establishing systems to collect and analyze failure data (e.g., mean time between failures). Identifying the highest-risk maintenance tasks on which training and procedure writing efforts should focus.

3.1 The concept of Risk and its relevance to maintenance

One of the main objectives of an effective maintenance strategy is the minimization of risk, caused by the unexpected failure of equipment. In addition, the strategy has to be cost effective.

Using a risk-based approach ensures a strategy, which meets these objectives. Such an approach uses the information obtained from the study of failure modes and their consequences.

Risk analysis is a technique of identifying, characterizing, quantifying and evaluating the loss from an event. Risk anlysis approach integrates probability and consequence analysis at various stages of the analysis and attempts to answer the following questions.

- What can go wrong that could lead to a system failure?
- How can it go wrong?
- How likely is its occurrence?
- What could be the consequences, if it happens?

In this context risk can be defined as

$$\text{Risk} = \text{Probability of failure} \times \text{Consequences}$$

Risk assessment can be either quantitative or qualitative. The result of quantitative risk assessment is typically a number, which is the cost impact in dollars ($) per unit time. The number could be used to prioritize a series of items that have been risk assessed. Quantitative risk assessment requires a great deal of data both for the assessment of probabilities and the assessment of consequences. The Fault trees are used to determine the probability that a certain sequence of events will result in a certain consequence.

A qualitative assessment presents a logical and structured argument for defining particular risk levels. Typically a qualitative assessment assigns frequency and consequence into broad bands and compares this to established risk acceptance criteria. A wide range of qualitative assessment techniques is available, but they are particularly useful for preliminary studies, maintenance (or other short term) activities, organizational changes and where meaningful data is not available. However, as these risk values are subjective, prioritizations based on these values are always debatable.

The RBM strategy aims at reducing the overall risk of failure of major systems and subsystems in the power plant. For the systems with high and medium risk, a focused maintenance effort is required, whereas in areas of low risk, the effort is minimized to reduce the total scope of work and cost of the maintenance program in a structured and justifiable way.

The risk based maintenance methodology is broken down into three main modules risk assessment, risk evaluation and maintenance planning as given in Figure – 3.1. Holyrood thermal power plant (unit 3) is selected to study and implement the RBM methodology. The Unit 3 is divided into major systems based on the operational characteristics. Then, the functions of each piece of equipment, subsystem and major systems are studied after developing flow charts.

Risk assessment combines frequency and consequence assessment results to portray the risk of undesirable events of major systems in Unit 3. Typical study involves analysis of failures and functional failures, fault tree development and analysis (Probabilistic failure analysis) to estimate the frequency of undesirable events and consequence analysis to estimate the economic losses during each failure. Finally, the results of the consequence and the probabilistic failure analysis are used to estimate the risk existing in unit 3.

Risk evaluation is the process by which risks are examined in terms of costs and benefits, and evaluated in terms of acceptability of risk considering the needs, issues and concerns of the unit 3. The acceptance risk criterion is determined based on the yearly maintenance expenditure of unit 3. Now, the acceptance criterion is compared with the estimated risk of individual major system, any value higher than this is unacceptable. The major systems whose estimated risk exceeds the acceptance criteria are identified. These are the units that should have an improved maintenance plan. Finally, an effective maintenance and inspection plan is developed for each major system and subsystem that exceeds the acceptance risk level. Detailed description of unit 3 and the various stages of implementation of the methodology are presented in the subsequent sections.

3.2 Introduction to Holyrood thermal power plant

A steam power plant is a means for converting the potential chemical energy of fuel into electrical energy. In its simplest form it consists of a steam generator and a turbine driving an electrical generator. In Newfoundland the operation of steam power plants started in 1969 at Holyrood. The first two units were built during the initial stage to provide a reserve back- up to the hydropower system. As the load increased, a third unit (referred as Unit 3) was added to Holyrood in 1979.

3.2.1 Unit 3

Unit 3 of the Holyrood power station has a rated capacity of 150MW. A single condensing steam turbine generator is supplied with steam from a 135 kilogram per second oil-fired generator. The Hitachi turbine-generator is designed to generate 150MW at 16 kV, 60Hz with throttle conditions 12,410 kPa at 538°C, reheat to 538°C and back pressure of 25.4mm Hg. The generator is hydrogen cooled and rated at 18.5 kVA, 0.85-power factor and is provided with Westinghouse static excitation.

The condensing plant consists of a Foster Wheeler two pass, divided water box, surface condenser designed to produce rated vacuum at a sea water inlet temperature of 5.5°C. Cooling water is circulated to the condenser by two fifty percent duty cooling water pumps from the sea.

The low pressure feed water system consists of two one hundred capacity condensate extraction pumps taking suction from the condenser hot well, a gland steam condenser, two low pressure feed water heaters and a tray type de-aerating heater. Two fifty percent duty fixed speed electric boiler feed pumps convey the feed water to the boiler via three high-pressure feed water heaters. The top heater draws bled steam from the cold reheat line, the others from the extraction points on the intermediate pressure and low-pressure turbines. The six stages of feed heating provide a final feed water temperature of 240.2°C.

The reserve feed water system consists of high and low level reserve feed water tanks and, provides water for variation in cycle flow requirements. The system is fully automatic in operation and serves to provide both adequate storage for make-up needs during boiler start up and a surge system, receiving from or supplying water to the low pressure feed water system as determined by the level of condensate in the condenser hot well. If the reserve feed water tank level is low, demineralized water from the water treatment plant is supplied to the condenser and transferred to the high level reserve feed water tank when the condenser hot well rises.

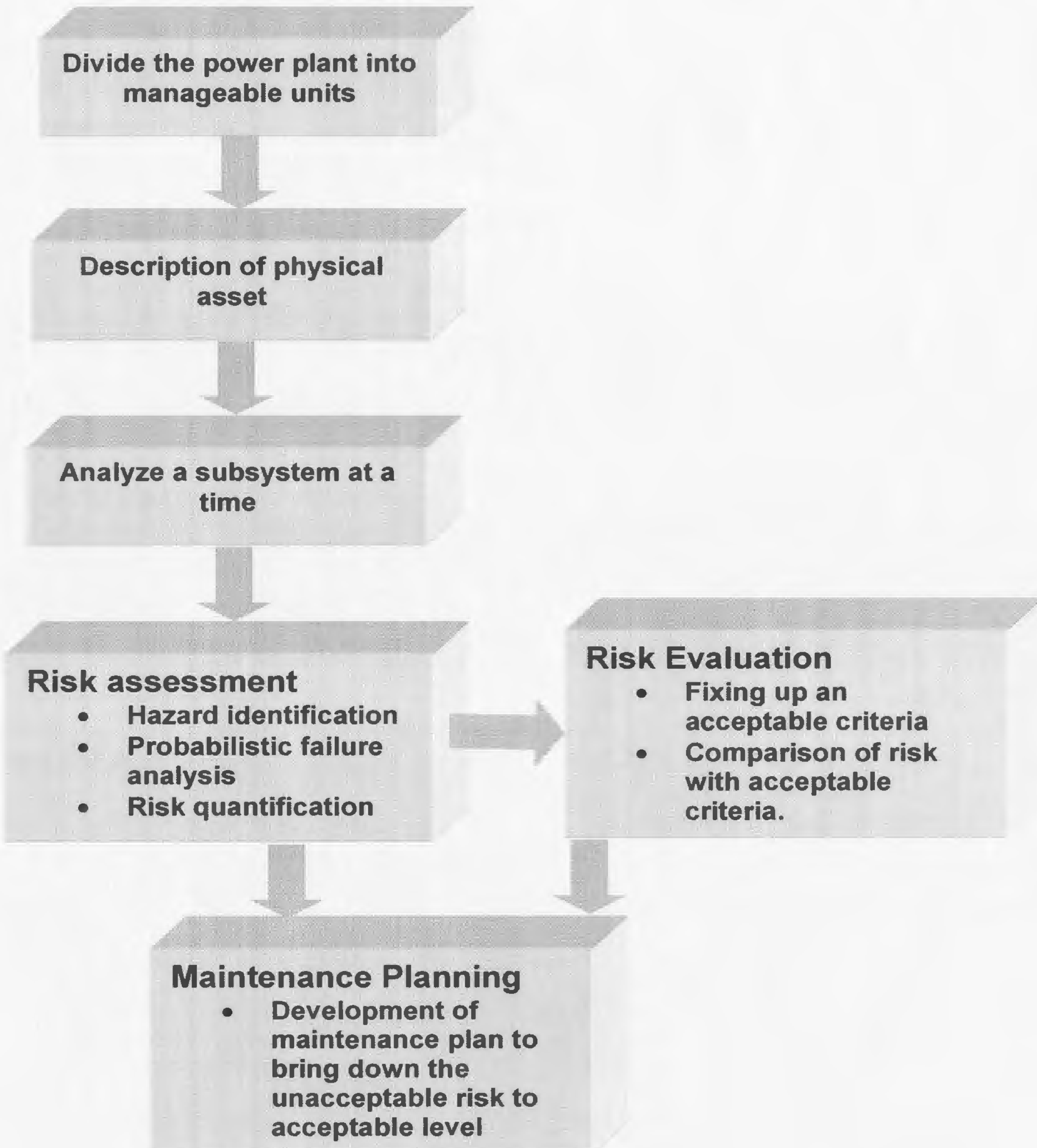


Figure 3.1 Architecture of RBM methodology (Ref: Khan and Haddara (2003))

The steam generator is a Bobcock & Wilcox Canada Ltd. radiant type oil fired unit pressurized furnace rated at 135 kg/sec, 13,030 kPa and 541°C with re-heats to 541°C. The boiler is designed to fire No.6 Bunker 'C' fuel oil under low excess air conditions using steam atomizing parallel throat burners. The steam generator has two case II 'R' type Ljungstorm regenerative air pre-heaters and two steam coil air heaters. Flue gases are discharged directly to a single 360 feet stack located immediately north of the main building.

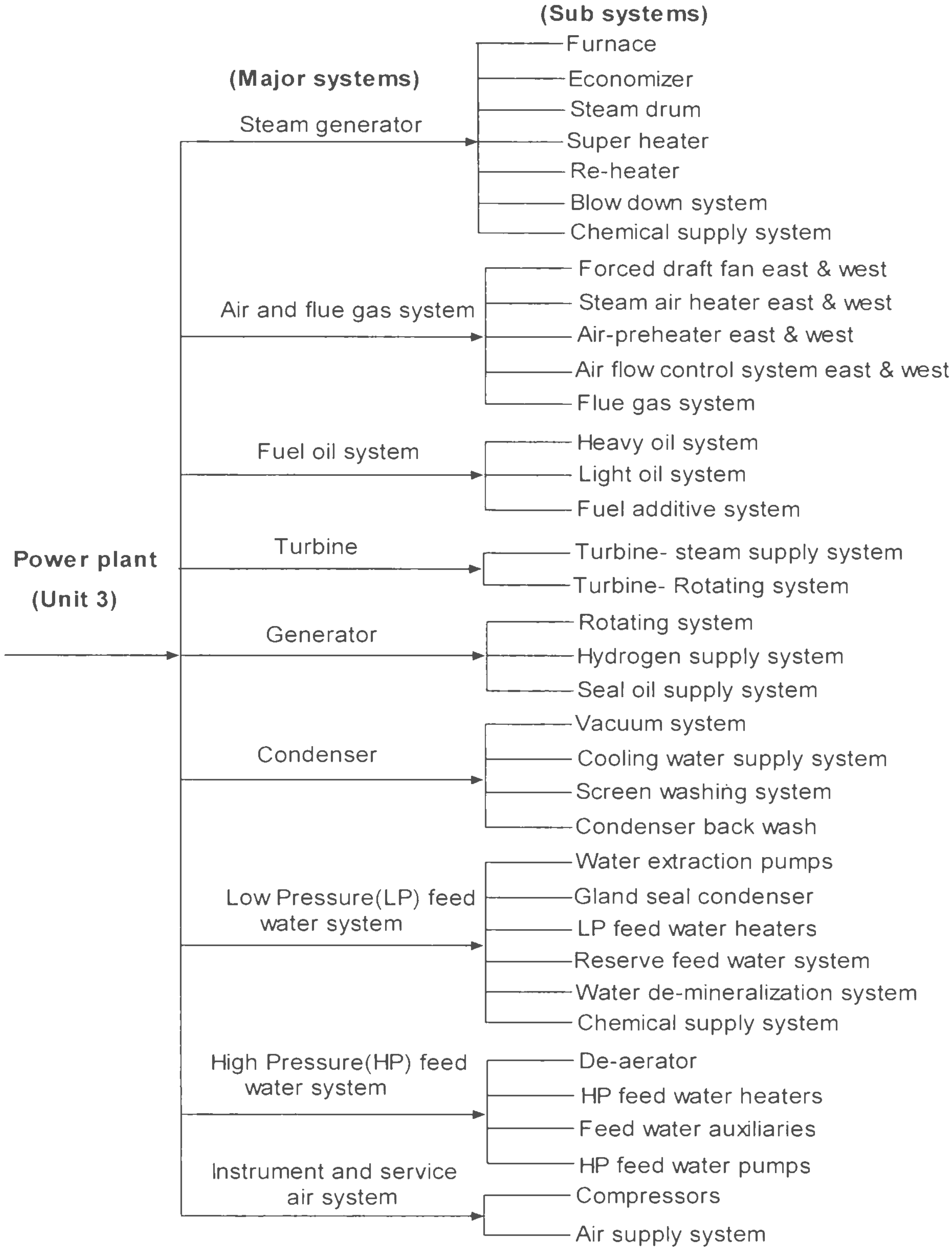
Heavy oil is stored in two oil storage tanks and the tanks are equipped with two suction heaters. The heated oil is discharged to the low-level day tank through gravity. The heavy oil is pumped to the boiler through duplex heavy oil pumping and heating set. Light oil (No.2 diesel) is supplied for emergency firing and to start the steam generator from the cold start.

The auxiliary steam supplies approximately 13,610 kg/hr of steam at 1380 kPa, 218°C for power plant auxiliary services. The water treatment plant supplies demineralized water for make-up needs. Instrumentation and control systems provide the necessary control for the proper operation of the plant.

3.3 Components of Unit 3

Unit 3 is divided into ten major systems based on the operational characteristics. A major system in the plant comprises of several subsystems. Again the major systems are further divided into subsystems and equipments to simplify the analysis. Figure 3.2 gives the details of various major systems (second column) and the subsystems (third column) and its logical relationship to the whole system (Unit 3). A subsystem comprises of different equipments or devices and the typical examples would be pumps, feed water heaters, valves and soot blowers. In other way, a component is considered the smallest part in an assembly, several components together form an equipment, examples would be springs, bearings, valve seat, valve stem, and pump impeller. However, the analysis is not carried out at the component level, but at the equipment and subsystems level. The functional descriptions of the major systems are described in the following Chapter. Appendix – A has the relevant flow diagrams of the major systems and subsystems.

Fig. 3.2 Components of Unit 3



Chapter 4 Description of the physical asset

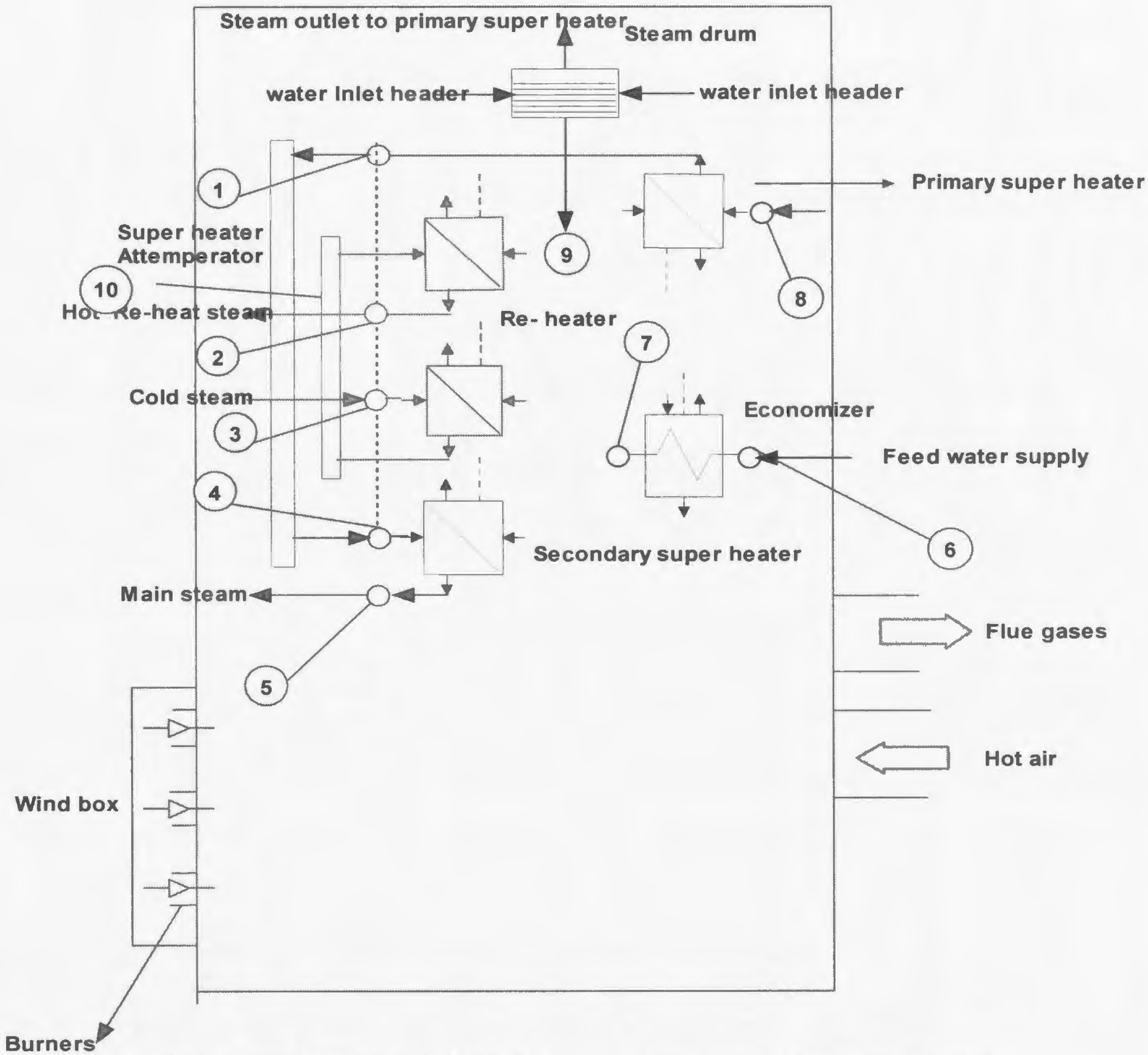
In the previous chapter, the different components of unit 3 are discussed. The functional description of steam generator and the components are discussed in this section. The detailed description includes physical location of systems, construction details, materials used for construction, metallurgical details, and the operational parameters. Refer to Annexure-A for the remaining major systems description. Appendix-B has the relevant flow diagrams.

4.1 Steam generator

The steam generator is a device for turning water into steam. It can be broken down into several components. First the combustion zone, where the fuel oil supplied by the fuel pump, is burned. Forced draft fans supply air for combustion. The resultant heat is used to convert water into steam. Boiler feed pumps supply water to the economizer, which supplies water to the steam drum. The economizer separates traces of saturated steam from water. The water collected in the steam drum flows through the down headers and enters the water walls, in the bottom of the furnace. Figure 4.1 shows the simplified flow diagram of the steam generator drawn using Smartdraw software.

As the water rises up, and is converted into saturated steam, it reaches a steam drum for the separation of water and steam. Saturated steam from the steam drum flows through primary and secondary super heaters, and is converted into superheated steam. The superheated steam enters the high-pressure section of the turbine for expansion. The steam after expansion enters into the re-heater as a cold reheat, and is heated within the steam generator. The hot re-heat enters into intermediate and low-pressure sections of the turbine for expansion.

The steam after expansion enters into the condenser and gets condensed as water in the hot well. The condensate is extracted by extraction pumps from the hot well and is supplied to the low pressure feed water heaters and, and then to the high pressure feed water heaters to raise the temperature of the feed water. The boiler feed pumps supply feed water to the economizer to increase the sensible heat of water. The generator, which is coupled to the turbine, develops



1. Primary super heater outlet header
2. Re- heater outlet header
3. Re- heater inlet header
4. Secondary super heater inlet header
5. Secondary super heater outlet header
6. Primary super heater outlet header
7. Economizer outlet header
8. Economizers inlet header
9. Down comers
10. Re- heater attemperator

Figure 4.1 Steam generator

power. The water-steam-condensate cycle is repeated again and again for the continuous generation of power. The steam generator is manufactured and installed by Bobcock&Wilcox Canada Ltd. It is a radiant type oil-fired unit rated at 135 kg/sec, 13,030 kPa and 541°C with re-heats to 541°C. It is designed to fire No.6 Bunker 'C' fuel oil under low excess air conditions using steam atomizing parallel throat burners

4.1.1 Furnace

The primary purpose of the furnace is to provide a gas tight enclosure for the complete combustion of fuel. It is a rectangular enclosure built with structure steel, and has provisions to keep all the steam generating equipments. The furnace has three linings: first, the ribbed outer casing, second, refractory lining, and the third water walls associated with input and output headers. The ribbed outer casing made from ribbed steel with wire mesh holds refractory lining together with water walls. The refractory lining provides good insulation to prevent heat losses in the boiler

The water walls raises from the bottom to the top of the furnace, spread on the four sides of the furnace walls. Water enters into these tubes and is converted into saturated steam as it rises up. Apart from these the furnace has provisions to enter and inspect it. Also, it has openings for burners, at three levels from the bottom.

4.1.2 Economizer

The function of an economizer in a steam-generating unit is to absorb heat from the flue gases and add this as sensible heat to the feed water before it enters the steam drum. The temperature of the feed water is increased and in some cases steam is generated. The economizer, which is, a finned tube type located below the primary super heater, in the steam generator gas pass. **[Refer to flow diagram 4.2]**

4.1.3 Steam drum

The steam drum of a re-circulating boiler receives the steam-water mixture from the evaporator tubes and separates this mixture into a water- free steam that flows to the super heater, and steam- free water goes to the down comers. The separation of the steam-water mixture rising from the generating tubes is achieved by use of internal baffling which can be in the form of cyclone separators, scrubbers, dry pipes dry pans or a combination of these components. Feed water from the economizer is added to steam is added to team drum to maintain a safe, normal water level in the drum. Apart from separating the steam and water, the steam drum is used for purifying the steam after separation. About five percent of feed water is continuously blown down, from the steam drum to the continuous blow down tank, for water sampling. The drum has provision for adding chemicals to feed water for the safer operation of the steam generator and accessories. **[Refer to flow diagram 4.3]**

4.1.4 Super heater

The heat content of the saturated steam is increased while it passes through the super heater. The super heater is divided into the primary and secondary super heaters. The primary super heater is located in the gas pass of the unit. The secondary super heater is located in the front gas pass of the unit where it receives heat by convection. Both the super heaters have their drains fitted and connected to the blow down tank.

The main steam from the boiler super heater outlet is fed to the high pressure (H.P) turbine through main steam piping system, turbine stop and control valve for expansion. The H.P turbine normally requires a constant pressure of 12,410 Kpa and 538°C. at the control valve. The main steam temperature is controlled with in steam generator by means of spray water attemperation between primary and secondary super heaters. The boiler combustion control system, controls the firing rate, to maintain a constant pressure of 12,410 Kpa at the throttle. The pressure transmitters on the main steam pipe at each turbine stop valve sense the pressure. **[Refer to flow diagram 4.4]**

4.1.4.1 Super heater De- super heater

The de-super heater or super heater attemperator is installed between the initial and finishing stage of the steam outlet. Steam from each end of the outlet header of the initial stage super heater flows through the de-super heater adjoining it and on to the inlet of the high temperature or finishing stage of the super heater. Located in this manner, the temperatures to which a de- super heater will be subjected are considerably less than if it were positioned after the final stage. Likewise, the possibility of carrying spray water over to the turbine will be eliminated when operating according to the outlined position.

A mechanical spray water nozzle is fitted in the middle of the super heater to make it possible to reduce steam temperature, when necessary, and maintains the same design value within the limits of the nozzle capacity. The water is supplied from feed water lines through automatic control valves. The temperature varies with the load, rising as the load increases and falling as the load decreases. With the constant load, the temperature should be kept constant.

4.1.5 Re-heater

Re- heaters are used on high-pressure units to heat the exhaust steam from the high-pressure turbine before it is admitted to the low-pressure turbine. After passing through the re-heater the steam returns to the intermediate pressure section of the turbine through the hot reheat piping system and combined reheat stop and intercept valves. The steam exhausted from the H.P turbine is at a temperature 316°C to 371°C and returns to the steam generator and re-heated to 538°C before passing to the intermediate pressure (I.P) turbine. This increases the efficiency of the steam cycle

Re-heat steam temperature is controlled by variable rate firing on the three burner levels, and in emergency, by spray attemperation, a pipeline spray attemperator being located in the cold reheat piping for this purpose. A control valve is linked to a separate automatic control drive unit regulates the flow of spray water supplied to the de- super heater. **[Refer to flow diagram 4.5].**

4.1.6 Blow down system

The steam generator and associated piping system are provided with safety valves, drain, vent and blow down valves. These components are required for safe and proper operation of the boiler.

4.1.6.1 Boiler drum

The two drains from the boiler drum discharges into the continuous blow down tank. This is a pressurized tank with the flashed steam line at the heater and the water cascading under the control loop to the blow down tank.

A small quantity of water is continuously drained from the steam drum for chemical analysis. The flow of this water is regulated by the two special, manually operated, angle valves. These valves are mounted in parallel and have high-pressure drop and ruggedized trim for flashing service.

4.1.6.2 Continuous blow down tank

The continuous blow down tank is maintained at the same pressure as the bled steam entering the de-aerating heater by connecting the tank vent to the bleed steam piping. Any flash steam entering from the blow down water therefore re-enters the thermal cycle and is recovered. The water collects in the bottom of the tank, the water level being controlled to provide a steam seal. The water drains, flows through control valve, to the blow down tank and from there to waste.

4.1.6.3 Blow down tank

This tank is a collector of high temperature and pressure drains. For safety reasons these cannot be drained directly to the plant discharge system but, instead, are permitted to stabilize to approximately atmospheric pressure conditions before discharge.

To prevent the steam from discharging into the plant drainage system, a seal is provided so that a water seal is maintained between the blow down tank and the drainage system.

4.1.6.4 Auxiliary steam system

Steam from the auxiliary steam system is taken from the primary super heater outlet header of the steam generator. The pressure reducing and de-super heating station provides outlet conditions for the auxiliary steam at 1380 Kpa and 218°C. The station is designed to handle a maximum flow of conditioned steam of 6.8 kg/sec and a minimum of 0.69 kg/sec. Estimated flow for an average winter day is 4.91 kg/s.

Two pressure safety valves are installed at the outlet of pressure reducing valve. A drain trap is fitted at the low point in the inlet piping to the de-super heater to prevent the possibility of water accumulating that could be carried through the steam and cause damage to the de- super heater and downstream equipment. The steam from the de-super heater is fed to the two steam air heaters, the de-aerator, the fuel oil pumping and heating set and the steam water mixer. The steam for the burners is reduced to a constant pressure of 1034 Kpa. Automatic on-off valves are installed on each burner for steam shut- off, steam purge and steam cooling. Estimated normal total flow to the burners is 0.255 kg/sec.

4.1.8 Steam drum chemical dosing

Sodium Phosphate is added to the steam drum water to precipitate dissolved solids including silica, chlorides and other matter. These precipitated solids are controlled at the desired minimum by continuously blowing down water from the steam drum. The system is provided with two 100% capacity positive displacement-metering pumps driven at constant speed by electric motors. The upstream and downstream manual isolating valves on the standby pump of each system are kept closed until the pump is required to run. The quantity of chemical solution discharged by the pumps is manually set by adjusting the calibrated eccentric on the seed reducer to alter the length of stroke. The discharge of phosphate is max 1.26 l/s. The phosphate tank is also provided with a motor driven agitator, which operates continuously to ensure that, the phosphate stays in solution.

Chapter 5 Failure data collection and modeling

The operating time data of the unit 3 is collected from January 1, 1997 to October 1, 2002. It consists of the dates and times when the operation of Unit 3 is commenced and ended. Also, dates and times between transitions of different system operating state, operating under forced de-rating, operating under a scheduled de-rating, available but not operating state, forced de-rating state, scheduled de-rating, forced outage state, forced extension of maintenance outage, forced extension of planned outage, maintenance outage state, and planned outage state were given along with outage codes. The aim is to separate the functional failures of Unit 3.

5.1 Failure and Functional failures

The functions that users expect from their assets can be split into two categories, primary functions that covers issues like speed, output, and carrying or storage capacity. Secondary functions, that concentrates in areas such as safety, control, containment, structural integrity, economy, protection, efficiency of operation, and compliance with environmental regulation.

Failure is defined as the inability of any asset to do what its users want it to do. Where as, functional failure is defined as the inability of any asset to perform a function according to the standard acceptable to the user. The different aspects of functional failures are partial and total failures. This definition of functional failure covers also the complete loss of function. It also covers situations where the asset still functions, but performs outside acceptable limits.

The generating component of unit 3 is comprised of all the equipment up to the high voltage terminals of the generator transformer and the station service transformer. The actual energy produced from the plant is referred to as the Maximum Continuous Rating (MCR). The MCR is defined as the maximum output in Mega Watts (MW) that a generating station is capable of producing continuously under normal conditions over a year. The MCR of the unit 3 is 150MW. A total failure or a forced outage means a condition, which requires that the generating unit be removed from service immediately. A partial failure forces the unit to operate at a de-rating state.

Thus, the generating unit is spinning and/or synchronized with the system but is not capable of producing its MCR.

So, the increased failure order times of a forced outage state and forced de-rating state of subsystems, equipments and components are tabulated. Functional failure is a random phenomenon and some probabilistic model is required to describe it. The objective is to derive the failure parameters from the failure times.

5.2 Failure and reliability function

Failure data obtained from the plant indicate that failure is a stochastic process. The stochastic phenomenon can be well described using probabilistic methods or concepts. The mathematics of probability is the mathematics of uncertainty, in that it is not possible to explain precisely the combinations of physical events, which cause the failure of the system. It is the mathematics of analyzing the chance events and predicting likelihood of events occurring during a given period of time.

In risk and reliability engineering a failure can be described as a random event. Mechanical reliability is the probability that the component, device or system will perform its prescribed duty without failure for a given period of time when operated correctly in a specified environment. Where as, the probability of an item failing up to a given time is complementary, in the mathematical sense, to the probability of the same item's survival (reliability). It follows that

$$R\ (t) + F\ (t) = 1$$

to express this relationship mathematically we define the continuous random variable t to be the failure time of the system on or before a time $T \geq 0$

Then the reliability can be expressed as

$$R\ (t) = P\ (T \geq t)$$

Where $R\ (t) \geq 0$, $R\ (0) = 1$, and $\lim_{t \to \alpha} R\ (t) = 0$. For a given value of t, R (t) is the probability that the time to failure is greater than or equal to t. So,

$$F\ (t) = 1 - R\ (t) = Pr\ (T < t)$$

Where

$$F(0) = 0$$

and

$$\lim_{t \to \alpha} F(t) = 1$$

Then F (t) is the probability that the failure occurs before time t.

We will refer to R (t) as the reliability function and F (t) as the cumulative distribution function (CDF) of failure or otherwise lifetime distribution. A third function, defined by

$$f(t) = \frac{dF(t)}{dt} = \frac{-dR(t)}{dt}$$

is called the probability density function (PDF). Given the PDF, f(t), then

$$F(t) = \int_0^t f(t)dt$$

$$R(t) = \int_t^\infty f(t)dt$$

the probability of failure occurring within some interval of time (a, b) may be found using any of the three probability functions, since

$$\Pr(a \le t \le b) = F(b) - F(a) = R(a) - R(b) = \int_a^b f(t)dt$$

5.3 Failure models

The failure models useful in describing the failure process are Exponential, Weibull, Normal and Lognormal probability distributions. The widely accepted Weibull and Exponential distributions are selected for failure analysis in this study.

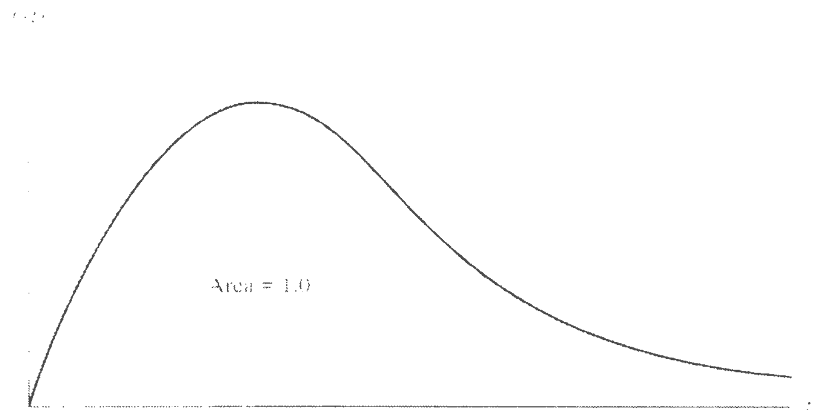


Fig 5.1 Failure density function

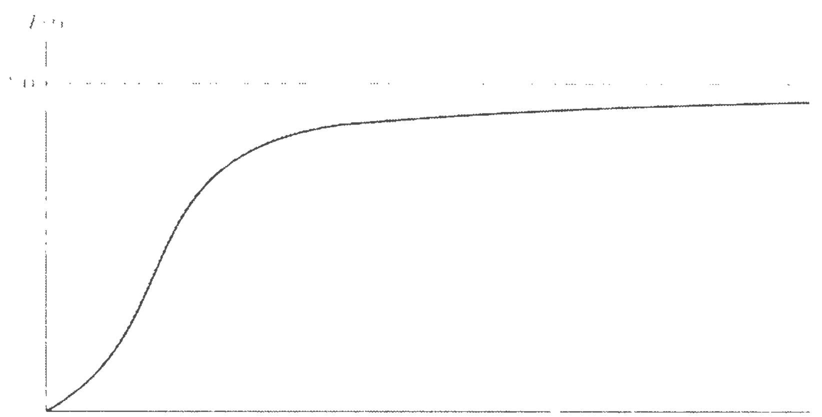


Fig 5.2 Cumulative failure probability function

5.3.1 Exponential distribution

Failures due to completely random or chance events will follow this distribution. Many systems exhibit constant failure rates, and the exponential distribution is in many respects the simplest reliability distribution to analyze. It should dominate during the useful life of a system or component.

Probability density function,

$$f(t) = \lambda e^{-\lambda t}$$

Probability distribution function,

$$F(t) = \int_0^t f(t)dt = 1 - e^{-\lambda t}$$

Reliability function,

$$R(t) = \int_t^\infty f(t)dt = e^{-\lambda t}$$

Mean time to failure is given by,

$$MTTF = \int_0^\infty e^{-\lambda t}dt = \frac{1}{\lambda}$$

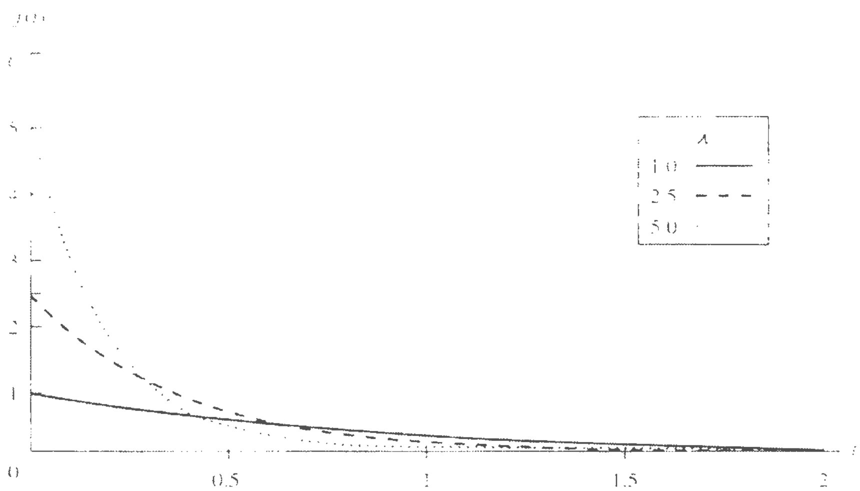


Figure 5.3 Exponential density function

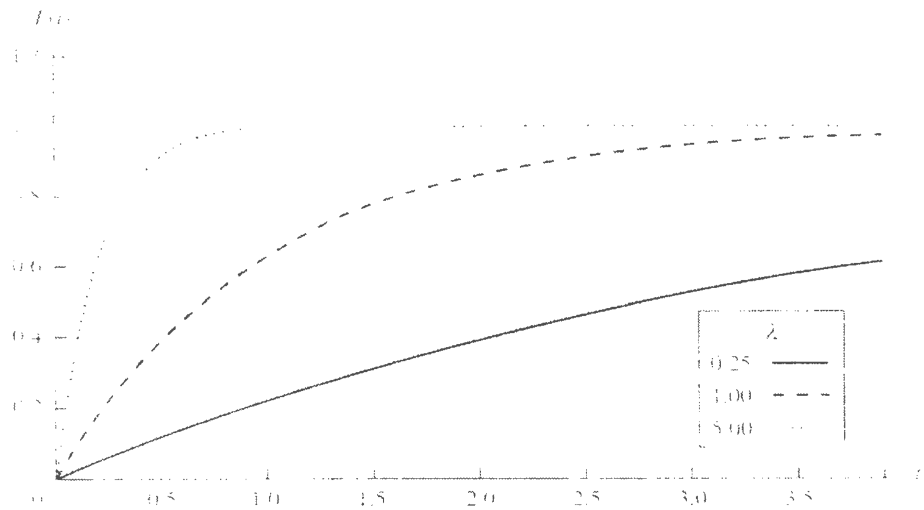


Figure 5.4 Exponential cumulative distribution function

5.3.2 Weibull distribution

Failure events, which have non-constant hazard rate functions over time, follow the Weibull distribution. The Weibull distribution is one of the most widely used lifetime distributions in reliability engineering. It is a versatile distribution that can take on the characteristics of other types of distributions, based on the value of the shape parameter, β. It can deal with decreasing, constant and increasing failure rates and can consequently model all phases of the bathtub curve. It is characterized by a hazard rate function of the form

$$\lambda(t) = at^{b}$$

Which is a power function. The functionλ (t) is increasing for a>0,b>0 and is decreasing for a>0, b<0. For mathematical convenience it is expressed as

$$\lambda(t) = \frac{1}{\theta}\left(\frac{t}{\theta}\right)^{\beta-1} \quad \theta > 0,\ \beta > 0,\ t \geq 0$$

$$f(t) = \frac{\beta}{\theta}\left(\frac{t}{\theta}\right)^{\beta-1} e^{-\left(\frac{t}{\theta}\right)^{\beta}}$$

$$F(t) = \int_{-\infty}^{t} f(t)\,dt = 1 - e^{-(t/\theta)^{\beta}}$$

$$R(t) = e^{-(t/\theta)^{\beta}}$$

Where (β) is the shape parameter and (θ) is the scale parameter, or characteristic life – it is the life at which 63.2 per cent of the population will have failed.

When $\beta = 1$, the exponential reliability function (constant hazard rate) results, with θ = mean life ($1/\lambda$).

When $\beta < 1$, we get a decreasing hazard rate reliability function.

When $\beta > 1$, we get an increasing hazard rate reliability function.

When $\beta = 3.4$, for example, the distribution becomes a Normal distribution. Thus the Weibull distribution can be used to model a wide range of life distributions characteristic of engineering systems.

The value of the shape parameter β provides insight into the behavior of the failure process. Table 5.1 summarizes this behavior.

Table 5.1 Weibull shape parameter

Value	Property
$0 < \beta < 1$	Decreasing failure rate (DFR)
$\beta = 1$	Exponential distribution (CFR)
$1 < \beta < 2$	Increasing failure rate (IFR)
$\beta = 2$	Rayleigh distribution (LFR)
$\beta > 2$	Increasing failure rate
$3 \le \beta \le 4$	Approaches Normal distribution

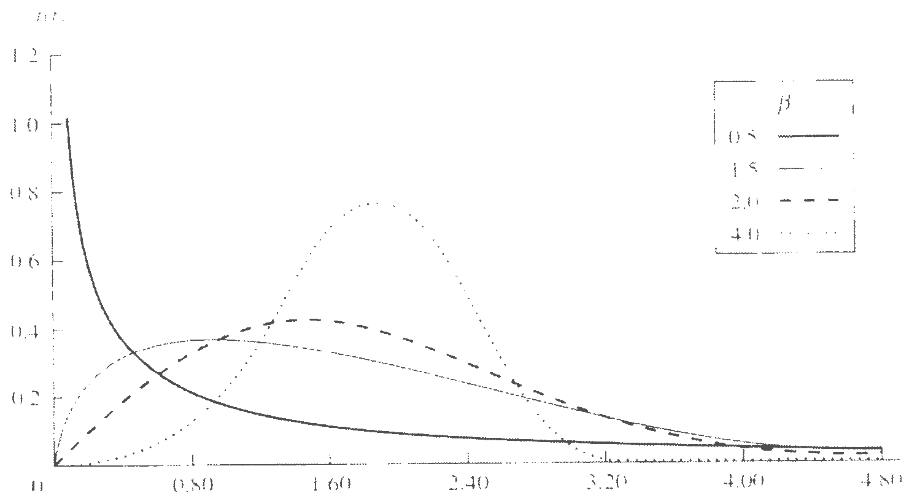


Figure 5.5 The effect of β on the weibull probability density function

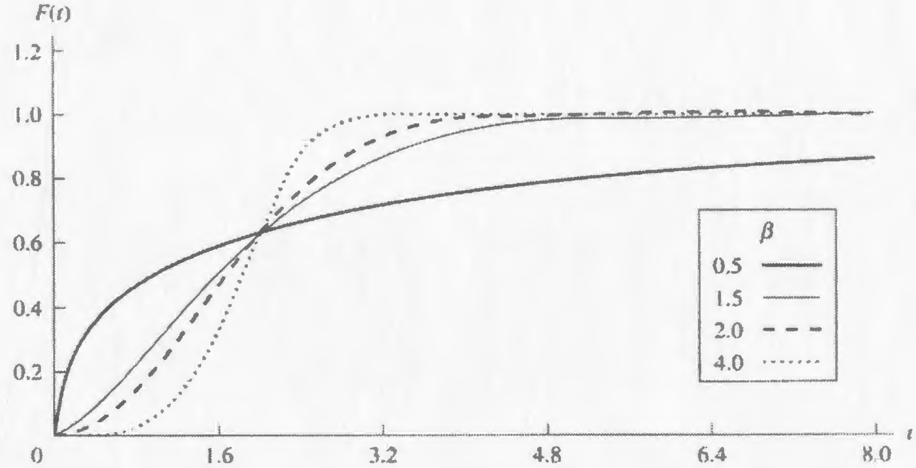


Figure 5.6 The effect of β on the weibull cumulative distribution function

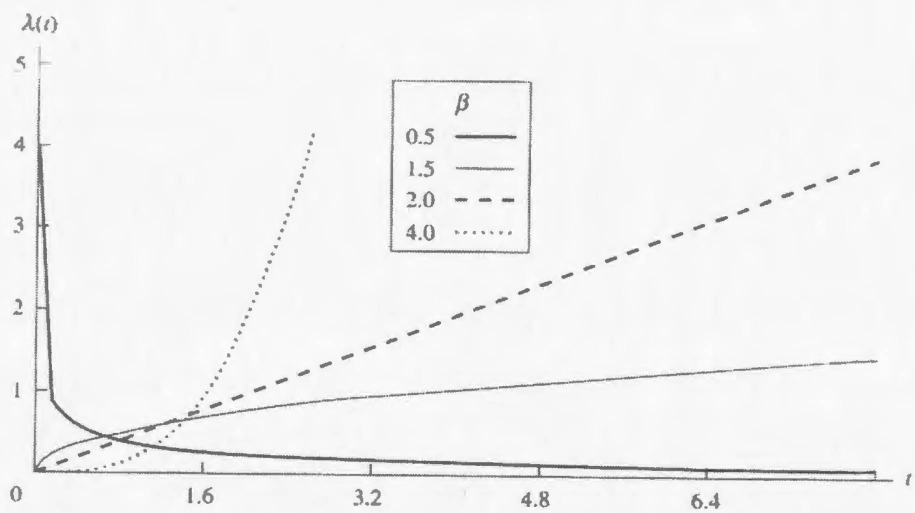


Figure 5.7 The effect of β on the weibull hazard rate curve

5.4 Hazard function

In addition to the probability functions defined earlier, another function, called the failure rate or hazard function, is often used in reliability. It provides as instantaneous (at time t) rate of failure. The hazard function along with bathtub curve is typically used as a visual model to illustrate the three key phases of equipment failures of Unit 3.

$$\Pr(t \le T \le t+\Delta t) = R(t) - R(t+\Delta t)$$

And the conditional probability of a failure in the time interval form t to t+Δt given that the system has survived to time t is

$$\Pr(t \le T \le t+\Delta t)/T \ge t)\,\mathrm{P} = \frac{R(t) - R(t+\Delta t)}{R(t)}$$

$$\lambda(t) = \lim_{\Delta t \to 0} \frac{-\left[R(t+\Delta t) - R(t)\right]}{\Delta t} \cdot \frac{1}{R(t)}$$

$$= \frac{-dR(t)}{dt} \cdot \frac{1}{R(t)} = \frac{f(t)}{R(t)}$$

Then λ(t) is known as the instantaneous failure rate or the hazard function. The failure rate function λ (t) provides an alternative way of describing a failure distribution. Failure rates in some cases may be characterized as increasing (IFR), decreasing (DFR), or constant (CFR) when λ(t) is an increasing, decreasing, or constant function respectively.

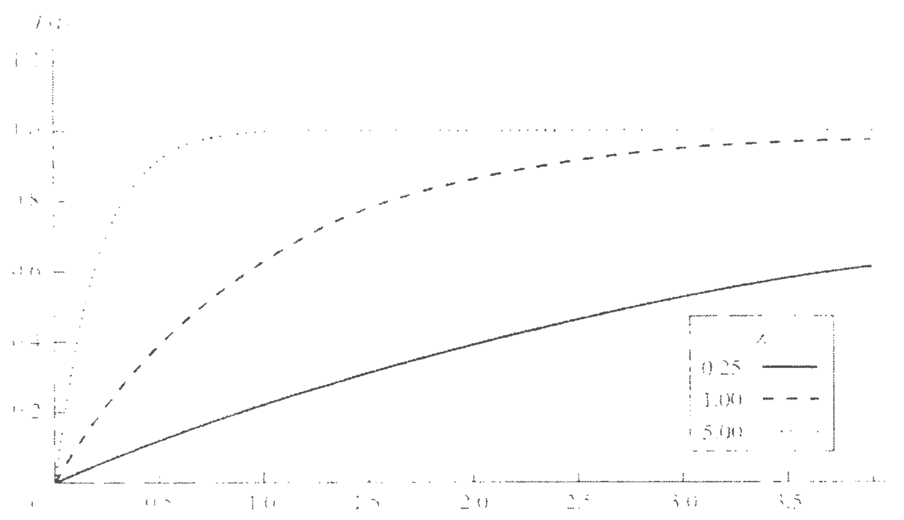


Figure 5.8 Hazard function

5.5 Bathtub curve

Reliability specialists often describe the lifetime of a population of products using a graphical representation called the bathtub curve. The bathtub curve consists of three periods: an infant mortality period with a decreasing failure rate followed by a normal life period (also known as "useful life") with a low, relatively constant failure rate and concluding with a wear-out period that exhibits an increasing failure rate. The bathtub curve is typically used as a visual model to illustrate the three key phases of equipment failures.

The bathtub curve, displayed in Figure 5.9, does *not* depict the failure rate of a single item, but describes the relative failure rate of an entire population of products over time. Some individual units will fail relatively early (infant mortality failures), others (we hope most) will last until wear-out, and some will fail during the relatively long period typically called normal life. Failures during infant mortality are *highly undesirable* and are always caused by defects and blunders: material defects, design blunders, errors in assembly, etc. Normal life failures are normally considered to be random cases of "stress exceeding strength." Wear-out is a fact of life due to fatigue or depletion of materials (such as lubrication depletion in bearings). Bathtub curve can be used to distinguish the failure pattern of equipments and subsystems in unit 3 based on the hazard rate. Also, it can be useful to find the failure causes of equipments, so that planned maintenance tasks can be applied easily. Table 5.2 summarizes some of the distinguishing features of the bathtub curve.

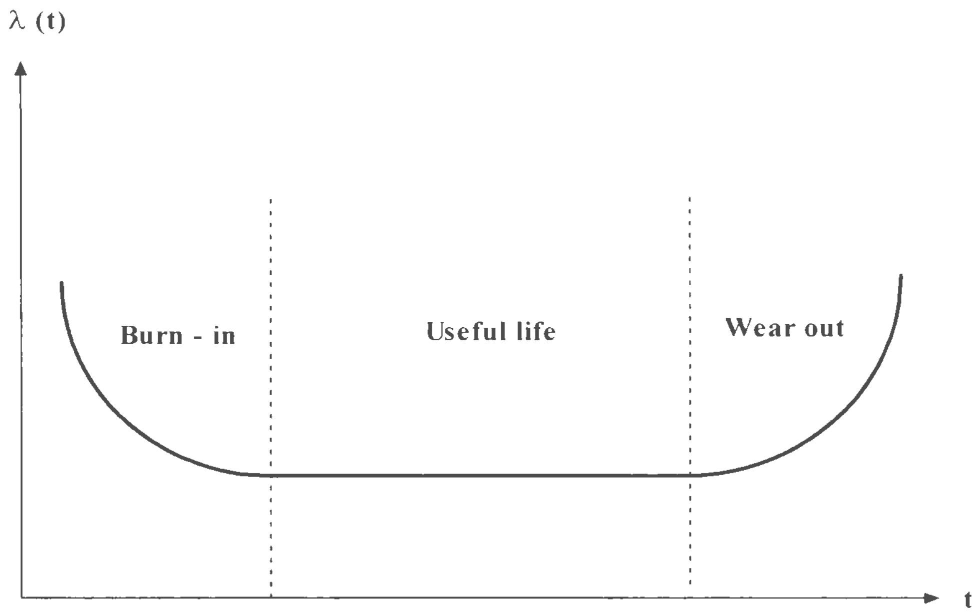


Figure 5.9 Bathtub curve

Table 5.2 Distinguishing features of the bathtub curve

Failure rate	Characterized by	Caused by	Reduced by
Burn-in	DFR	Manufacturing defects: Welding flaws, cracks, Defective parts Poor quality control, Contamination, Poor workmanship.	Burn-in testing Screening Quality control Acceptance testing
Useful life	CFR	Environment Random loads Human error Chance events	Redundancy Excess strength

Failure rate	Characterized by	Caused by	Reduced by
Wear-out	IFR	Fatigue Corrosion Aging Friction Cyclical loading	De-rating Preventive maintenance Predictive maintenance Parts replacement Redesign

5.6 Failure data modeling

The collection of failure data and various failure models used for describing the failure process is discussed in the previous sections. This section describes how to derive the parameters, directly from the failure times. The failure data collected from the various subsystems, equipment and components, is the complete data. The data are arranged in ascending order and the cumulative percentage failed at a particular value of t is used as an estimate of the failure distribution function F (t) at that time. The cumulative failure probability is calculated using the median ranking.

5.6.1 Mean ranking

A simple approach to estimate the distribution function of a sample size N is to assign 1/N for the estimate of F (t) at the first ordered failure time; 2/N at the second ordered time and so on. Thus,

$$F(t_i) = I/N \qquad \text{where } I = 1,2\ldots N$$

This distribution shows bias, in that the first failure is shown much further from zero probability than the last from 100%. It is better to make an adjustment to allow for the fact that each failure represents a point on the distribution. Other formulas for mean ranking which reduces the bias are

$$F(t_i) = I/(N+1) \qquad \text{where } I = 1,2\ldots N$$

And

$$F(t_i) = (I-1/2)/N \qquad \text{where } I = 1,2\ldots N$$

5.6.2 Median ranking

Mean ranking is the appropriate method for a symmetrical distribution, such as the Normal. However, for a skewed distribution median ranking provides a better representation. The most common approximation as suggested by B'enard (Connor, 1991) is given by

$$F(t_i) = \frac{i - 0.3}{n + 0.4}$$

Listing the increasing order of failure time's t_i, ranking the failure times starting from 1 to n and then the above formula is used to calculate cumulative failure probability. Once the failure probability is calculated the next step is to estimate the parameters.

Field data is often accompanied by noise. Even though all control parameters (independent variables) remain constant, the resultant outcomes (dependent variables) vary. A process of quantitatively estimating the trend of the outcomes, also known as regression or curve fitting, therefore becomes necessary. The terms linear regression and least squares are used synonymously in this reference. The term rank regression is used in the application instead of least squares, or linear regression, because the regression is performed on the rank values, more specifically, the median rank values (represented on the y-axis). Thus, a curve with a minimal deviation from all data points is desired. This *best-fitting curve* can be obtained by the method of least squares. The method of least squares requires that a straight line be fitted to a set of data points such that the sum of the squares of the distance of the points to the fitted line is minimized. This minimization can be performed in either the vertical or the horizontal direction. The regression is on Y, and then this means that the distance of the vertical deviations from the points to the line is minimized. Failure distributions are converted as given below to fit a straight line, the slope and intercept gives the estimate of the parameters.

5.6.3 Least – Squares fits

Exponential distribution

Rewriting the distribution in the form:

$$-\lambda t = \ln[1 - F(t)]$$

$$\frac{1}{\ln[1 - F(t)]} = \lambda t$$

y = mx

Weibull distribution

Rewriting the distribution as:

$$-(\lambda t)^{\beta} = \ln[1 - F(t)]$$

$$\ln \ln \frac{1}{[1 - F(t)]} = \beta \ln t - \beta \ln \theta$$

y = mx + c

The failure times (x_i) and their corresponding (y_i) are known, and then from the following equations we can estimate the slope m and the intercept c of the straight line

y = mx + c

$$m = \frac{n\sum_{i=1}^{n} x_i y_i - \left(\sum_{i=1}^{n} x_i\right)\left(\sum_{i=1}^{n} y_i\right)}{n\sum_{i=1}^{n} x_i^2 - \left(\sum_{i=1}^{n} x_i\right)^2}$$

$$c = \frac{\sum_{i=1}^{n} y_i \sum_{i=1}^{n} x_i^2 - \left(\sum_{i=1}^{n} x_i\right)\left(\sum_{i=1}^{n} x_i y_i\right)}{n\sum_{i=1}^{n} x_i^2 - \left(\sum_{i=1}^{n} x_i\right)^2}$$

For Weibull distribution the value of m is the value of β and the value of exponential, minus of intercept divided by β gives the value of θ. For exponential distribution the value of m is equal to the value of λ. An example of failure data analysis of subsystem Boiler is shown in table 5.3 using Excel. Weibull failure distribution model is used to fit the data.

To test the adequacy of the regression model the R^2 and F-values are estimated from the data. The *R-square* value is the square of the correlation coefficient between X and Y, an indicator of how well the model fits the data. F – Value is the test for comparing the model variance with residual variance. If the variances are close, the ratio will be close to one and it is less likely that any of the factors have a significant effect on the response. If the Prob > F value is very small (less than 0.05) then the terms in the model have significant effects on the response. After, comparing both the R^2 value and F-value between the different failure models discussed above, the most suitable model is selected. Weibull failure model is selected for Boiler. The same procedure is used for all the equipments and the results are tabulated. These failure parameters are used in probabilistic failure analysis and will be discussed in chapter 6.

Table 5.3 Failure data anlysis using Weibull model and the results

Outage Code	Date of failure	Time of failure	Failure time	(I)	F(ti)	Xi= Ln(ti)	Yi=lnln(1/1-F(ti)	XiYi	Xi*2
12	04.04.92	5.30	10997.3	1	0	9.31	-3.067873	-28.5	86.59
12	04.04.92	6.25	10998.2	2	0.1	9.31	-2.145823	-20	86.59
12	01.05.92	21.04	11661.0	3	0.2	9.36	-1.646281	-15.4	87.68
12	08.05.92	20.00	11828.0	4	0.2	9.38	-1.291789	-12.1	87.95
12	20.05.92	17.30	12113.3	5	0.3	9.4	-1.010261	-9.5	88.4
21	30.11.92	16.00	16768.0	6	0.4	9.73	-0.771668	-7.51	94.62
21	13.02.96	6.26	44838.2	7	0.4	10.7	-0.560288	-6	114.7
21	20.03.96	14.00	45686.0	8	0.5	10.7	-0.366513	-3.93	115.1
21	09.04.96	16.00	46168.0	9	0.6	10.7	-0.18361	-1.97	115.3
21	01.05.96	0.00	46680.0	10	0.6	10.8	-0.006117	-0.07	115.6
12	02.05.96	9.00	46713.0	11	0.7	10.8	0.171265	1.84	115.6
21	05.05.96	9.30	46785.3	12	0.8	10.8	0.354898	3.82	115.6
21	08.04.02	8.00	98696.0	13	0.8	11.5	0.554526	6.38	132.2
12	30.04.02	22.20	99238.2	14	0.9	11.5	0.790156	9.09	132.4
						144	-9.17938	-83.9	1488

Beta	1.17836774
Intercept	-12.76963331
Theta	50853.95901

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.890392
R Square	0.792798
Adjusted R Square	0.775531
Standard Error	0.518369
Observations	14

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	12.33748	12.33748	45.9144	1.9692E-05
Residual	12	3.224473	0.268706		
Total	13	15.56195			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*
Intercept	-12.7696	1.793131	-7.12142	1.21E-05	-16.676529
X Variable 1	1.178368	0.173903	6.776016	1.97E-05	0.79946624

Table 5.4 Failure parameters of various equipments of Unit 3

Major system	Serial No	Subsystem/ Equipment	Outage code	Parameter
1. Steam generator	1.1	Boiler	31000	β–1.17, θ–50853.9 H
	1.2	Burners	31270	β–1.65, θ–40215.4 H
	1.3	Re-heater	31702	λ=1.74E-05 H
	1.4	Water walls	31540	β–1.27, θ–57746.9 H
	1.5	Burner Piping and valve	31230	λ - 0.17/year
	1.6	Igniters	31280	λ - 9.51E-06 H
	1.7	Boiler control	63100	β–1.98, θ–49061.1 H
	1.8	Controls furnace draft	63200	λ - 0.25/year
	1.9	Steam Ins. & Control	63400	λ - 0.08/year
	1.10	Auxiliary steam and condensate system	73100	λ - 0.16/year
2. Fuel oil supply system	2.1	Fuel oil Management Ins & Control	63700	β–1.77, θ–52219.9 H
	2.2	Combustion Control	63900	λ - 2.90E-05 H
	2.3	F.D fan # 1	32310	β–1.26, θ–52523.1 H
	2.4	F.D fan # 2	32310	λ - 3.00E-05 H
	2.5	F.D fan motor # 1	32330	λ - 4.90E-05 H
	2.6	F.D fan motor # 2	32330	λ - 2.11E-05 H
	2.7	Fuel oil transfer system	37300	λ - 0.16/year
	2.8	Fuel oil forwarding system	37400	λ - 0.08/year
	2.9	Fuel oil boosting system	37500	β–2.18, θ–72895.4 H
3. Air and flue gas system	3.1	Air pre-heater 1	31150	λ - 1.50E-05 H
	3.2	Air Pre-heater 2	31150	λ - 2.00E-05 H
	3.3	Air extraction system	45000	λ - 0.08/year
	3.4	Air extraction vacuum pumps	45100	λ - 0.08/year
	3.5	Gland seal system	41500	λ - 0.08/year

Major system	Serial No	Subsystem/ Equipment	Outage code	Parameter
4. Turbine	4.1	Turbine rotors	44120	λ - 0.08/year
	4.2	Steam turbine aux. Ins. & con.	64100	λ - 0.16/year
	4.3	Turbine bearing #2	41100	λ - 0.08/year
	4.4	Pedestal bearing # 1	41170	λ - 0.08/year
5. Generator	5.1	Hydrogen gas cooling system	42300	λ - 0.08/year
	5.2	Generator brushes	42114	λ - 0.08/year
6. Condensate system	6.1	Condenser tubes	44120	β–1.51, θ–74607 H
	6.2	Condenser	44110	λ - 1.50E-05 H
	6.3	Feed water piping and support	43090	λ - 3.10E-05 H
	6.4	Condensate make-up system	47000	λ - 0.08/year
	6.5	Condensate make-up system Ins.& Control	64700	λ - 0.16/year
7. Feed water system	7.1	Boiler feed pump 1	43000	β–1.18, θ–33925.7 H
	7.2	Boiler feed pump 2	43200	β–1.34, θ–34845.6 H
	7.3	HP heater 4	43100	λ - 0.0001 H
	7.4	HP heater 5	43100	β–2.9, θ–40607.4 H
	7.5	HP heater 6	43100	λ- 0.08/year
	7.6	Feed cycle auxiliary	48000	λ - 0.08/year
	7.7	Boiler feed water Ins & Control	64300	β–2.21, θ–69743.4 H
	7.8	Feed water heater Ins& Control	64800	λ - 0.08/year
	7.9	De-aerator	44500	λ - 0.16/year

5.7 Uncertainties

Estimating population from inaccurate, deficient or biased data, which results in errors and information losses, causes uncertainties. This leads to difference between population and sample properties. The collected failure data of unit 3 have two types of uncertainties. The first is called as non-homogeneity in data, not coming from the same location. The second most important type of uncertainty is the sampling error. This has occurred due to estimating statistics from samples from an infinite population.

5.8 Failure patterns of equipments

The graphical representation of the lifetime of the equipment is illustrated in section 5.5 with bathtub curve. Moreover, the value of the shape parameter β estimated from the failure data provides insight into the behavior of the failure process of the equipments of Unit 3. Most of the equipments operates reliably for a period and then wear out. Most of the maintenance decisions are based on this assumption and planned to take preventive action shortly before the item is due to fail in future. This bathtub model is true in certain types of simple equipments. But, the power plant is more complex system with variety of electrical and mechanical items and the failure pattern is altered as shown in the Figure 5.10

Pattern A is well known bathtub curve. It begins with a high incidence of failure (known as infant mortality followed by constant or gradually increasing conditional probability of failure, then by wear-out zone. Pattern B shows constant or slowly increasing conditional probability of failure (Hazard rate), ending in wear-out zone. Pattern C shows slowly increasing conditional probability of failure, but there is no identifiable wear-out age. Pattern D shows a constant conditional probability of failure at al ages (random failure). The study of failure patterns of equipments shows that 18% of the items conformed to Pattern B, 9% to C and the remaining 73% to D. The rest of the components other than this are conformed to Pattern D. Moreover, preventive maintenance has no effect on random failures (Charles, 1997).

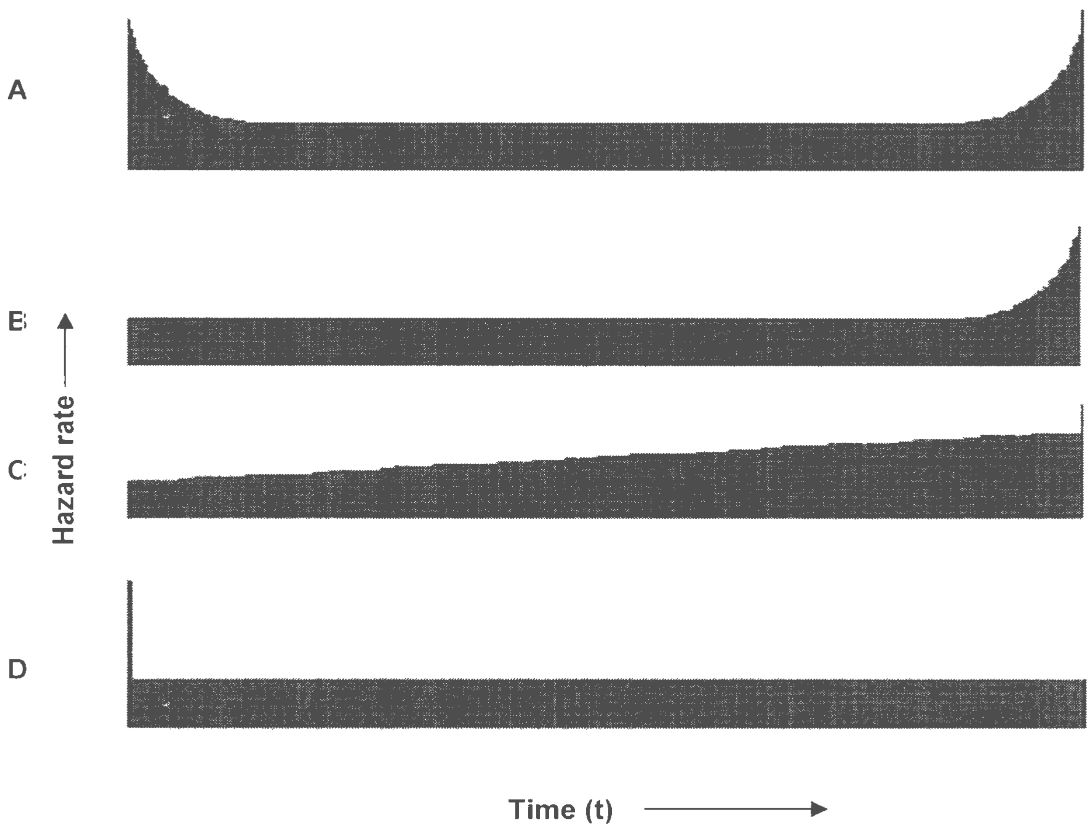


Figure 5.10 Failure patterns

Table 5.5 Failure Patterns of important equipments

Failure pattern	Serial No	Subsystem/ Equipment	Outage code	Parameter
Pattern C	1.1	Boiler	31000	β-1.17, θ-50853.9 H
	1.2	Water walls	31540	β-1.27, θ-57746.9 H
	1.3	F.D fan # 1	32310	β-1.26, θ-52523.1 H
	1.4	Boiler feed pump 1	43000	β-1.18, θ-33925.7 H
Pattern B	2.1	Burners	31270	β-1.65, θ-40215.4 H
	2.2	Boiler control	63100	β-1.98, θ-49061.1 H
	2.3	Fuel oil Management Ins & Control	63700	β-1.77, θ-52219.9 H
	2.4	Fuel oil boosting system	37500	β-2.18, θ-72895.4 H
	2.5	Condenser tubes	44120	β-1.51, θ-74607 H
	2.6	Boiler feed pump 2	43200	β-1.34, θ-34845.6 H
	2.7	HP heater 5	43100	β-2.9, θ-40607.4 H
	2.8	Boiler feed water Ins & Control	64300	β-2.21, θ-69743.4 H

Chapter 6 Risk assessment, evaluation and maintenance planning

6.1 Risk assessment

This module is comprised of four steps, which are logically linked as shown in Fig. 6.1. A detailed description of each step is presented below.

6.1.1 Failure scenario development

A failure scenario is a description of a series of events, which may lead to a system failure. It may contain a single event or a combination of sequential events. Usually a system failure occurs as a result of interaction of a sequence of events. The acceptance of a scenario does not mean it will indeed occur, but that there is a reasonable probability that it would occur. A failure scenario is the basis of the study of risk: it tells us what may happen, so that preventing or minimizing the possibility of its occurrence of an unwanted event can be devised. After fixing the boundaries of each system, and the associated boundary interfaces (i.e., inputs, outputs) failure scenarios are developed. Such scenarios are generated based on the functional failure of the system. Functional failures are identified based on the guidelines given in the unit 3 operating manual and manufacturers equipment's manuals. The failure scenarios are incorporated during fault tree development and analysis.

6.1.2 Probabilistic failure analyses

Probabilistic failure analysis is conducted using a fault tree analysis (FTA). The use of FTA, together with components' failure data, enables the determination of the frequency of occurrence of the failure of a system. Developing probabilistic fault trees is made easier using a methodology called "analytical simulation" (khan, Abbasi, 2001).

The key features of this step are:

a) Fault tree development: The top event is identified based on the detailed study of the process, control arrangement, and behavior of components of unit 3. A logical dependency between the causes leading to the top event (functional failure) is developed. The details of the Fault tree development is discussed in the section 6.2.3.

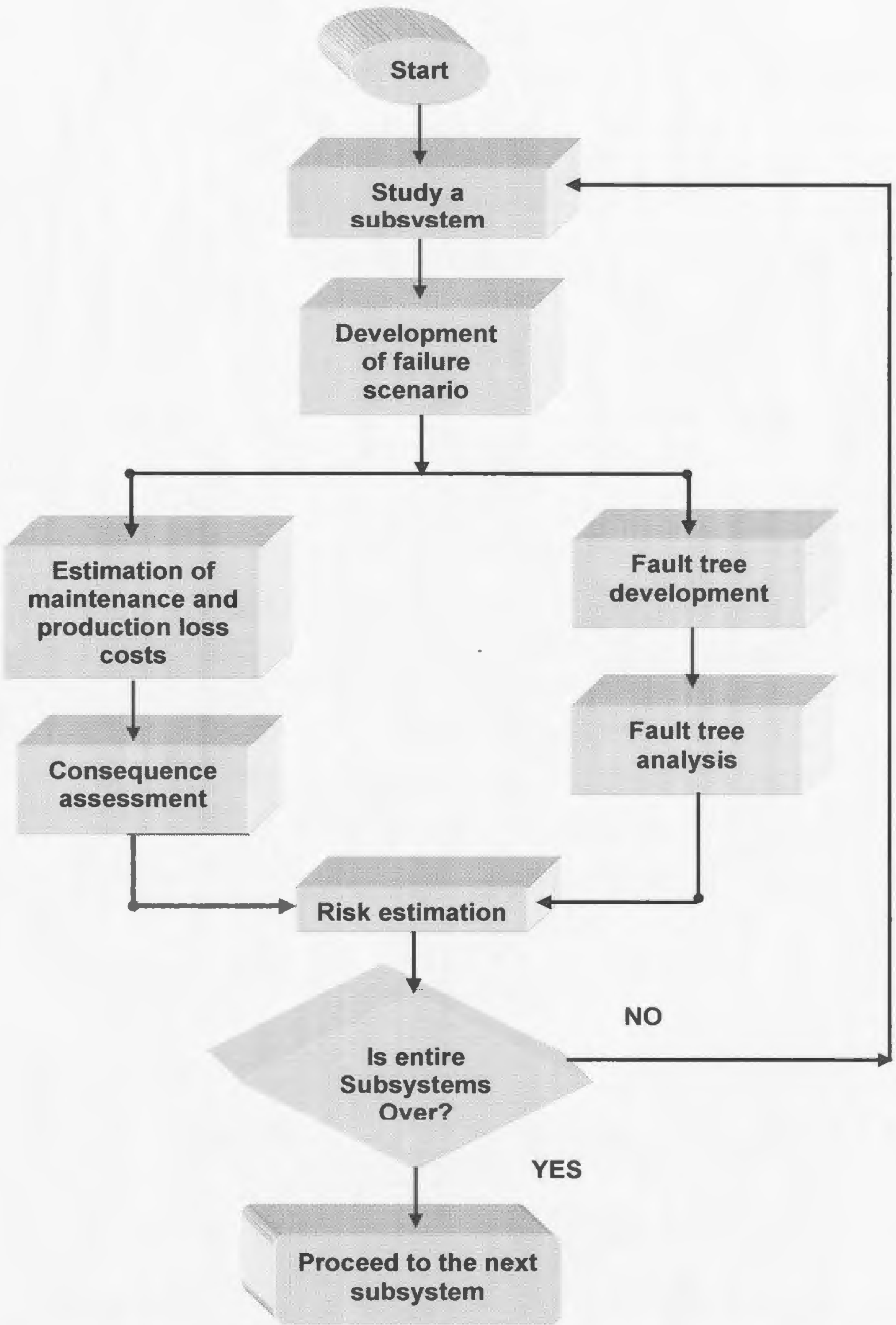


Fig. 6.1 Description of risk estimation module (Ref: Khan and Haddara (2003))

b) Boolean matrix creation: The fault tree having basic events in series, and/or parallel and their combination can be represented in a binary function as

1, if a basic event is true

0, if a basic event is not true

in a similar way, fault tree for the complete system (unit: 3) can be represented as a combination of these basic events in terms of Boolean matrix function:

F_k = matrix[jbi]

$$\begin{matrix} 1b1 & 1b2 & 1b3 & \ldots & 1bn \\ 2b1 & 2b2 & 2b3 & \ldots & 2bn \\ . & . & . & \ldots & . \\ mb1 & mb2 & mb3 & \ldots & mbn \end{matrix}$$

Where, jbi represents the element Boolean matrix, j represents a row, and I represents a column.

The system function F_k is defined as:

1, system fail (undesired event occurs)

0, system is working (undesired event does not occur)

Where, k represents the number of times a system function F is true or in other words, the cutsets of the fault tree.

Once the complete system is represented in terms of jbi (basic events) using Boolean algebra, it is further evaluated using an analytical method to identify the dependency of F on the basic elements jbi. The evaluation of dependency gives the combination of basic events that can lead the system function F to a fail condition (undesired event to occur). These combinations of basic elements, also known as minimal cutsets, give insight into the system.

For a real-life industrial problem, the number of these minimal cutsets may be very large. Hence the concept of 'optimal minimal cutsets', which represents the cutsets having direct dependency on the top event (having frequency/ probability of occurrence higher than a minimal value). The minimal cutsets can be optimized by using any standard optimization procedure. However the use of modified Fibonacci (Marchisotto, 1993) search method is the best tool to optimize the minimal cutsets. The optimal minimum cutsets can be represented as;

$G(X^i)$ = minimum $[U_j=1,1\ [jg^i]\ ]$

For jg^i >= minimal criteria

$jg^i = PI_i = 1$, m $[p(X^i)]$ where

m $[p(X^i)] = n(X^i)$ * base duration * boundary limitations

where

i represent the event

j represent the number of cutsets

X^i represents state of variable

P (X^i) probability of occurrences of an event

Jg^i = probability of a cutset

$n(X^i)$ frequency of failure rate of an event i

$g(X^i)$ represent optimized minimal event set

The optimized minimal cutsets are exceedingly important as they represent the core combination of events susceptible to cause an undesirable event. For a typical fault tree, which consists of a large number of basic events and gates the optimal cutsets of each module are linked with other modules according to their control barrier dependency. This step is repeated till all modules of the problem are combined. This combination finally gives the optimal minimum cutsets for the complete system.

c) Analysis of optimal minimal cutsets using fuzzy set theory: In simple set theory, the probability of occurrence of top event, through optimal minimal cutsets, P^{Topn} is described by a function of the basic events.

$P^{Top} = h[P(X^1), P(X^20, \ldots, P(X^{i-1}) \ldots P(X^n)]$

The probability of occurrence of top event when one event X1 has been eliminated or made not to fail can be representd as:

$P^{Top1} = h[0, P(X^2), \ldots, P(X^{i-1}) \ldots P(X^n)]$

While considering these probabilities, an improvement factor has been defined as a factor representing an event's contribution to the undesired event. As per definition, an improvement factor signifies the improvement in the probability of occurrence of the top event (undesired event). The higher the improvement factor for an event, the more likely it is going to cause the undesired event. Mathematically, an improvement factor for an event is represented as;

$(P^{Top} - P^{Top\ 1}) > 0$ = improvement factor

The simple set theory requires exact values of probabilities of each event described by optimal minimal cutsets to estimate the probability of undesired event, and the improvement factor. Even small deviations (uncertainty) in these values (probability data of basic events) get accumulated and thus lead to high deviation of the result.

As discussed earlier, getting exact values of failure data is very difficult. To allow for inaccuracies in the failure data, fuzzy probability space concepts are used to decrease the dependency of the analysis on the reliability data. In the present context, fuzzy probability space means the probability of an event expressed in terms of a fuzzy set. Among various forms of fuzzy probability set representations, the trapezoidal representation is useful. For example; the probability of occurrence of an event xi is expressed as:

$P(X^i) \Delta = (qil, pil, pir, qir)$

Where $fP(X^i)$ = represents a fuzzy probability

Such that;

$$
fP(X^i) \quad
\begin{cases}
= 0 & \text{for } qil \geq p(x) \geq 0 \\
= 1 - \{pil - p(X)\} / \{pil - qil\} & \text{for } pil \geq p(x) \geq qil \\
= 1, & \text{for } pir \geq p(x) \geq pil \\
= 1 - \{pil - p(X)\} / \{pil - qil\} & \text{for } qir \geq p(x) \geq pir \\
= 0 & 1 \geq p(x) \geq qir
\end{cases}
$$

Using the same procedure as discussed in simple set theory, the probability of occurrence of a top event can be expressed as

$P^{Top} = h[\,P(X^1), P(X^2), \ldots P(X^i), \ldots + P(X^n)]$

$P^{Top}\,\Delta = (qtl, ptl, ptr, qtr)$

The probability of occurrence after eliminating element, xi can be represented as:

$P^{Top1} = h[0, P(X^2), P(X^3), \ldots P(X^i), \ldots + P(X^n)]$

$P^{Top1} = ((qt1l, pt1l, pt1r, qt1r)$

And finally the improvement factor can be calculated as:

$P^{Top} - P^{Top1}$ = improvement

All computations are carried out in a fuzzy probability space. The final probability of occurrence and the improvement factor are also calculated in terms of fuzzy probability sets. Later the fuzzy probability is transformed to normal probability using the trapezoidal average function.

The results obtained using this concept are more reliable compared to the results obtained by other methods with the same level of uncertainty in the input data. It is mainly because the single probability values are transformed in a well-defined space and all calculations are done in the same space. Doing that, the error in the data is also distributed to wider space and computation in this space causes lesser error accumulation. Eventually, the fuzzy probability can be transformed to normal probability as desired. using average function.

Further, the improvement factor has been used to formulate an improvement index. This index gives a direct measure of the sensitivity of the top event to any preceding event. The higher the index the more sensitive is the system to that particular event. Using the index one can identify the basic events, which need greater attention if the probability of the top event (failure) has to be reduced. Fuzzy probability set theory is used in analytical simulation algorithm and coded in PROFAT software (Khan and Abbasi, 2001). The Analytical simulation methodology and PROFAT is shown in Fig. 3.3

6.1.3 Fault tree development

As discussed earlier, a fault tree is a logical and hierarchical model of an undesirable situation expressed in terms of all possible sequences and combinations of intermediate and basic events or failure modes leading to the ultimate undesired situation, or top event. In general a fault tree model consists of four fundamental types of events described as:

(i) an event that corresponds to a primary failure in the system,

(ii) an event that corresponds to a functional failure of the system,

(iii) an event that corresponds to a non-primary failure that is not decomposed into more basic events,

(iv) an event hat does not correspond to a fault or failure but is an ordinary event existing inherently within the system.

6.1.4 Functional failures and failure modes

Failure can be defined as the inability of a system or system component to perform a required function within specified limits. A failure may occur when a fault is encountered. A functional failure is defined as the inability of a system or a system component to perform a required function to a standard of performance, which is acceptable to the user. Engineering systems fail due to different reasons. A failure mode is any event, which causes a functional failure. The causes are

- Deterioration

Any physical asset that fulfils a function, which brings it into contact with the real world, is subject to a variety of stresses. These stresses cause the asset to deteriorate by lowering its capability, or more accurately, its resistance to stress. Eventually resistance drops so much that the asset can no longer deliver the desired performance – in other words, it fails. Deterioration covers all forms of 'wear and tear' (fatigue, corrosion, abrasion, erosion, evaporation, degradation of insulation, etc). These failures have been included in a list of failure modes wherever they thought to be reasonably likely.

- Lubrication failures

Lubrication is associated with two types of failure modes. The first is caused by the lack of a lubricant, and the second is caused by the failure of lubricant itself. Dirt or Scaling The common cause of failure or falling in performance of power plant is ash formation, fireside deposition and scaling.

- Disassembly

These are usually failure of welds, soldered joints, or rivets due to fatigue or corrosion r the failure of threaded components such as bolts, electrical connections or pipe fittings, which can also fail due to fatigue or corrosion.

- Human errors

These refer to errors, which reduce the capability of the process to the extent that it is unable to function as required by the user. However, the human errors are not included in this study.

- Design errors

Design errors are of the form under capacity, over capacity, incorrect specification of materials and components and errors in the basic design of components. There are no details available to include this during the analysis.

- Material defects
- Maintenance deficiencies

Apart from the failure modes discussed above, different types of failures and failure modes are obtained from the study of plant history cards, and maintenance manuals and are incorporated during fault tree development. Failure anlysis is not performed on every failure mode of a single component (Maurizio Bevilacqua, 2000). This approach was choosen for the following reasons:

(i) Such detailed level analysis is usually too burdensome

(ii) The common causes of the analyzed equipment are practically always due to seals, valve seating and bearings.

Fault tree analysis is both qualitative and quantitative. The qualitative analysis consists of identifying the various combinations of events that will cause the top event to occur. This is followed by a quantitative analysis to estimate the probability of occurrence of the top event. There are four major steps to a fault tree analysis:

- Defining the system, its boundaries, and the top event.
- Constructing the fault tree, this symbolically represents the system and its relevant events.
- Performing the qualitative evaluation by identifying those combinations of events that will cause the top event.
- Performing a quantitative evaluation by assigning failure probabilities to the basic events and computing the probability of the top event.

In construction of a fault tree, the two logic gates, the OR gate and the AND gate, are used to relate the resultant, basic, and intermediate events to the top event. Lower events are input to a gate, and higher event is the gate's output. The type of gate determines whether all input events must occur for the output event to occur (AND gate) or whether only one of the input events must occur for the output event to occur (OR gate). Fault tree of steam generator is given below. Refer to **Appendix- B** for the rest of the fault trees of the entire unit 3.

6.1.5 Selecting and fixing failure parameters for basic events

Once the fault tree is developed the next step is to find the failure probability of basic events. Before finding the failure probability, the failure parameters for those basic events are allocated. The following three-fold procedure is used:

1. Failure parameters are fixed from the estimated parameters using power plant failure data.

2. The data collected from the operating plant does not contain failure data for all equipment, especially valves and other major components. For these components the failure rates were determined from data obtained from the reliability data banks. Refer to Appendix-C for the MTBF

confidence limits in determining failure rates of items with zero failures given in Non-electronic parts reliability data book (Denson, 1995).

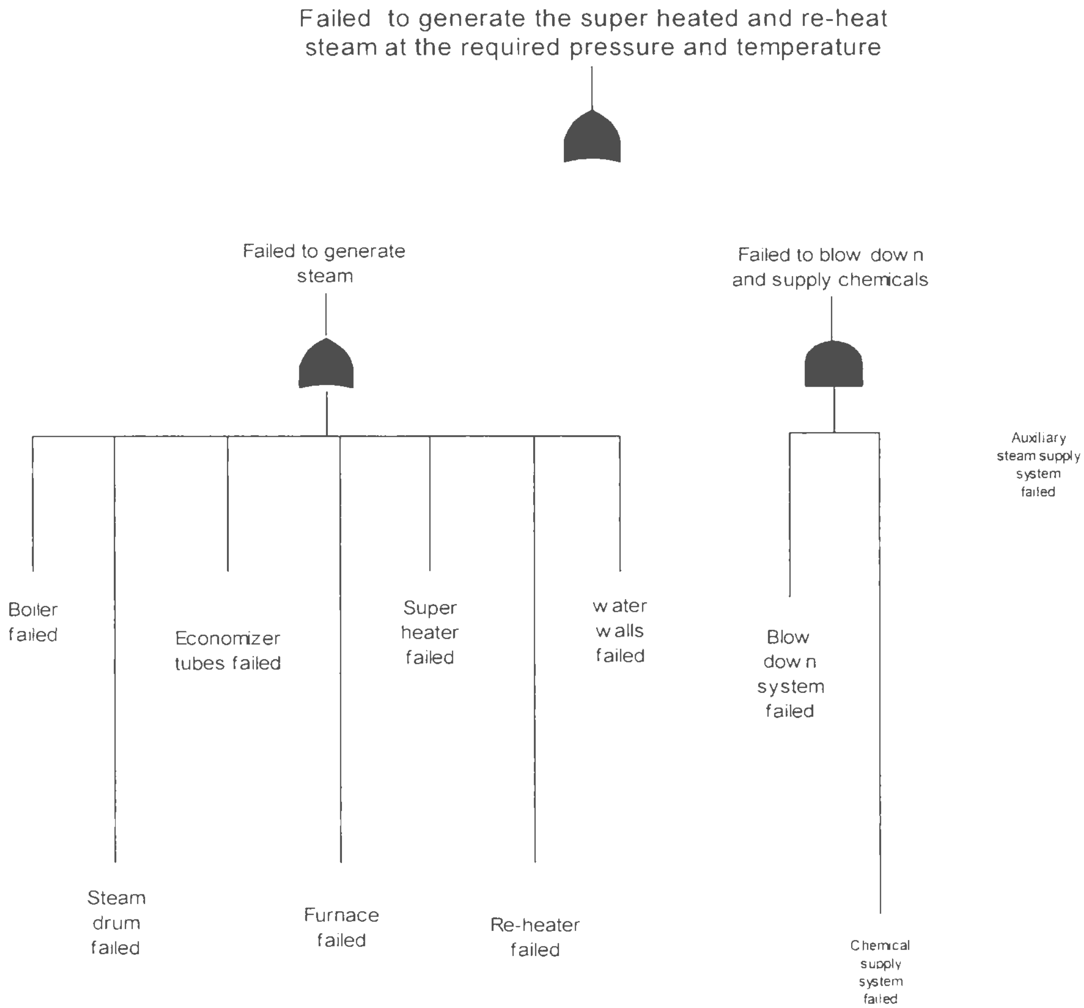


Fig 6.2 Fault tree for a steam generator

This method is followed during selecting and determining failure parameters for the components with random failures For example, the globe valve, N.O 23047-006 - style: packaged unit, POP: 20 (Page 3-549), the data given as 0/2.9170. The failures are 0.The hours are 2,917 x 10^^6 hours or 2917000 hours. Using the equation as shown in the PDF, the lower confidence interval is calculated as 2(2917000)/0.619 = 9424878.837 hours (MTBF). The failure rate is the inverse of the MTBF. This gives a failure rate of 0.106 failures/million hours. Similarly the upper value is 2(2917000)/4.47 = 0.766 failures/million hours.

3. The failure rates for the basic events that are rare events (subjective) and whose data are available neither from data banks nor from the plant data are determined from operating experience and by consulting with the plant personnel. Table 6.1 gives the failure rate data for machinery components from field statistics.

Table 6.1 Failure rate data

Reliability	$\lambda \times 10^{-6}$
Extremely Reliable	0.01
Highly reliable	0.01 - 0.1
Good reliability	0.1 - 1.0
Average reliability	1.0 - 10.0
Very unreliable	10.0 - 100.0
Intolerable	> 100

Source: Atomic Energy of Canada Ltd.

6.1.6 Estimating the probability of failure of basic events

Based on the failure parameters, failure probability is calculated for the period of 20 years by selecting suitable Exponential and Weibull failure probability functions. **Appendix- D** has the values of failure parameters and failure probability calculations.

Exponential failure probability function $F(t) = \int_{-\infty}^{t} f(t)dt = 1 - e^{-\lambda t}$

Weibull failure probability function $F(t) = \int_{-\infty}^{t} f(t)dt = 1 - e^{-(t/\theta)^{\beta}}$

6.1.7 Fault tree analysis

Once the fault tree is developed for any undesired event in unit 3 then it can be evaluated to identify the pathways, which would lead to the undesired events. Subsequently, using the failure probability of the basic events, these pathways can be further evaluated to estimate the frequency of the top event. Using the software package PROFAT (Probabilistic Fault Tree analysis) the analysis is performed and the results for the steam generator are tabulated in Table 6.2. Table 6.3 has the consolidated results of unit 3.

Table 6.2 PROFAT results of steam generator

IMPROVEMENT INDEX RESULTS

Event not-occuring	Probability	Improvement Index	Improvement
0	9.986943e-01	0.000000e+00	0.000000
1	9.974116e-01	5.130589e-03	11.188756
2	9.974116e-01	5.130589e-03	11.188756
3	9.969181e-01	7.104814e-03	15.494133
4	9.974116e-01	5.130589e-03	11.188756
5	9.973937e-01	5.202055e-03	11.344608
6	9.973937e-01	5.202055e-03	11.344608
7	9.974285e-01	5.062878e-03	11.041092
8	9.983252e-01	1.476347e-03	3.219609
9	9 983252e-01	1.476347e-03	3.219609
10	9.974597e-01	4.938602e-03	10.7700733

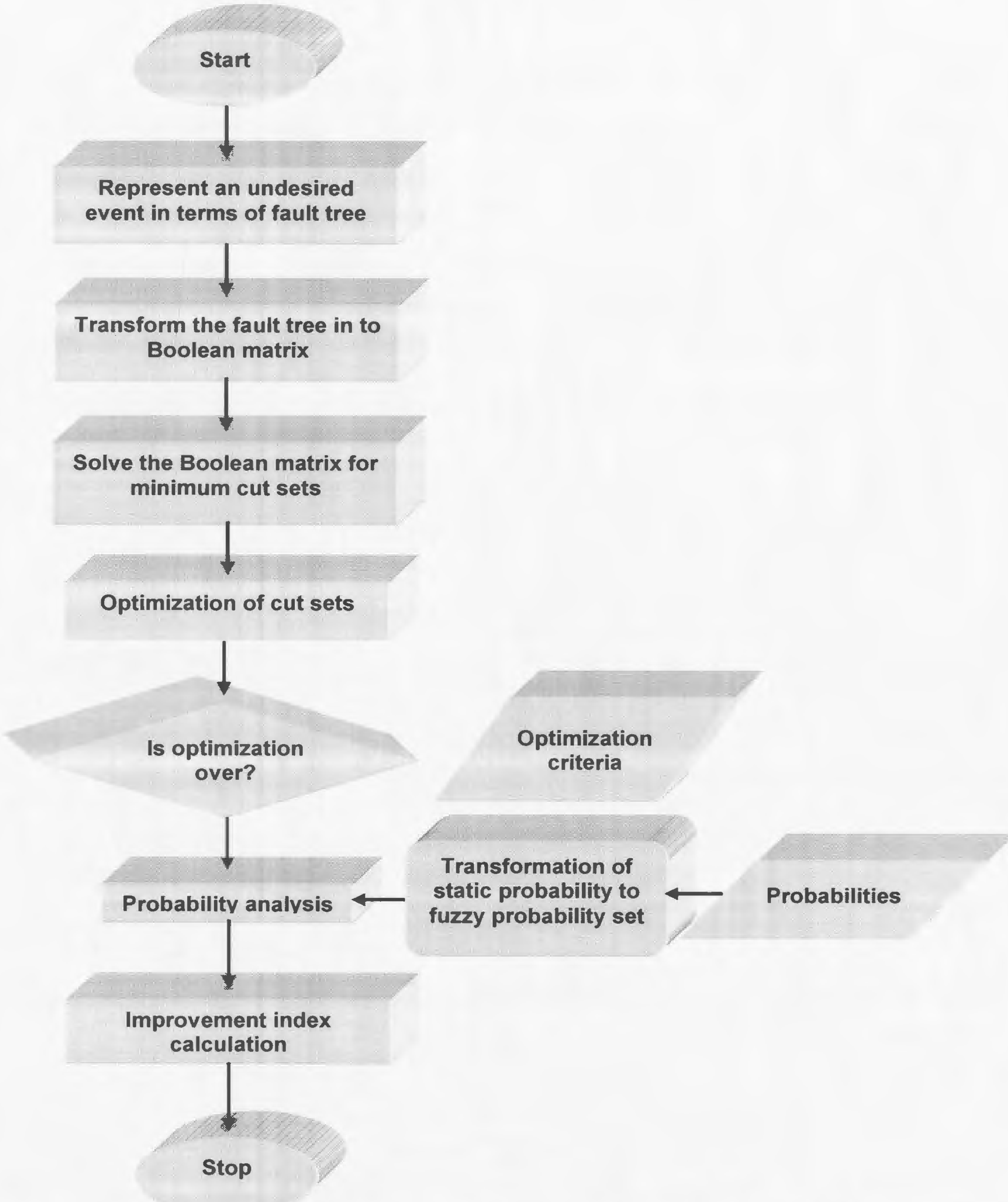


Figure 6.3 Analytical simulation methodology and PROFAT (Ref: khan, Abbasi (2001))

Table 6.3 Fault tree analysis results of Unit # 3

S.No	Major system	Subsystem	Failure scenarios	Probability of failure in 20 years
I	Power plant: Unit 3		▪ Failed to generate steam ▪ Failed to supply water ▪ Failed to generate power ▪ Failed to start steam generator	0.9999
1.	Steam generator		▪ Failed to generate steam ▪ Failed to blow down and supply chemicals ▪ Auxiliary steam supply system failed	0.9986
1.1		Furnace	▪ Failed to ignite the fuel ▪ Heat transfer rate low ▪ Unable to run	0.9825
1.2		Economizer	▪ Failed to supply water to steam drum ▪ Failed to vent the gases ▪ Failed to raise the temperature of water	0.6291
1.3		Steam drum	▪ Failed to separate water and steam ▪ Failed to supply water to down comers ▪ Failed to relieve pressure ▪ Presence of moisture in the steam	0.9855
1.4		Super heater	▪ Failed to raise the temperature of steam ▪ Failed to relieve the pressure ▪ High super heated temperature ▪ High super heated pressure ▪ Failed to supply spray water	0.9925
1.5		Re-heater	▪ Failed to re-heat the steam ▪ Unable to spray water in the attemperator ▪ Failed to supply and spray water ▪ Failed to control the reheat steam temperature	0.9970

S.No	Major system	Subsystem	Failure scenarios	Probability of failure in 20 years
1.6	Steam generator	Blow down system	▪ Failed to draw water from steam drum ▪ Failed to supply water to tank 1 ▪ Failed to supply water ▪ Unable to drain water ▪ Failed to low down water from all the headers	0.9733
1.7		Chemical supply system	▪ Failed to pump sodium phosphate ▪ Failed to supply sodium phosphate	0.9786
2.	Air and flue gas system		▪ Failed to supply air to furnace ▪ Failed to supply air at right proportion ▪ Flue gas system failed	0.9991
2.1		Forced draft fan west	▪ Unable to run ▪ Inlet damper drive system failed ▪ Both inlet and outlet dampers failed to open	0.9662
2.2		Forced draft fan east	▪ Unable to run ▪ Inlet damper drive system failed ▪ Both inlet and outlet dampers failed to open	0.9969
2.3		Steam air heater west	▪ Failed to supply steam at the required pressure ▪ Failed to supply steam to air heater ▪ Failed to heat the air ▪ Failed to drain the condensate	0.9557

S.No	Major system	Subsystem	Failure scenarios	Probability of failure in 20 years
2.4	Air and flue gas system	Steam air heater east	▪ Failed to supply steam at the required pressure ▪ Failed to supply steam to air heater ▪ Failed to heat the air ▪ Failed to drain the condensate	0.9557
2.5		Air pre-heater west	▪ Unable to run the forced draft fan ▪ Failed to raise the temperature of air to the designed value	0.9724
2.6		Air pre-heater east	▪ Unable to run the forced draft fan ▪ Failed to raise the temperature of air to the designed value	0.9729
2.7		Air flow control system west	▪ Failed to send input signal to air flow master station in west from three levels ▪ Failed to control dampers at three levels in west	0.9568
2.8		Air flow control system west	▪ Failed to send input signal to air flow master station in west from three levels ▪ Failed to control dampers at three levels in west	0.9568
2.9		Flue gas system	▪ Excessive flue gas temperature ▪ Failed to detect and send oxygen level signal to combustion control system ▪ Failed to remove flue gases	0.9720
3.	Fuel oil system		▪ Failed to supply oil to day tank ▪ Failed to supply oil to burners ▪ Failed to supply additive	0.9866

S.No	Major system	Subsystem	Failure scenarios	Probability of failure in 20 years
3.1	Fuel oil system	Heavy oil system	▪ Failed to supply oil to main header ▪ Failed to control temperature ▪ Unable to control firing	0.9989
3.2		Light oil system	▪ Failed to supply clean oil to pumps ▪ Failed to pump oil at the required pressure ▪ Failed to relieve pressure ▪ Failed to supply oil to main pipe ▪ Failed to supply light oil and air to the bottom level burners	0.9921
3.3		Fuel additive system	▪ Failed to supply magnesium hydroxide at three levels ▪ Failed to supply additive to main header	0.9201
4a.	Turbine: steam supply system		▪ Failed to supply main steam to intermediate pressure (IP) turbine ▪ Failed to drain water tin the main pipe line ▪ Failed to supply reheat steam to re-heater ▪ Failed to supply reheat steam to Low pressure (LP) turbine ▪ Failed to drain water in the re-heater pipe line ▪ Failed to control the super heated steam pressure and temperature ▪ Failed to control re-heated steam ▪ Pressure and temperature	0.9999

S.No	Major system	Subsystem	Failure scenarios	Probability of failure in 20 years
6.4		Condenser back wash	▪ Failed to initiate back wash ▪ Failed to perform back wash	0.7821
7.	Low pressure feed water system (LP)		▪ Pumping and heating system failed ▪ Failed to supply water during make-up ▪ Failed to supply chemicals ▪ Failed to supply water	0.9995
7.1		Water extraction	▪ Extraction pump # 1 failed to supply water ▪ Extraction pump # 2 failed to supply water	0.9865
7.2		Gland seal condenser	▪ Failed to vent the gases ▪ Failed to supply steam ▪ Failed to drain water ▪ Heat transfer rate reduced	0.8556
7.3		LP heater # 1	▪ Failed to vent and purge gases ▪ Failed to supply steam through pipe 1& 2 ▪ Failed to drain the water from drain tank ▪ Failed to drain water during abnormal level rise	0.9998
7.4		LP heater # 2	▪ Failed to vent and purge gases ▪ Failed to supply steam through pipe 1& 2 ▪ Failed to drain the water from drain tank ▪ Failed to drain water during abnormal level rise	0.9900

S.No	Major system	Subsystem	Failure scenarios	Probability of failure in 20 years
7.5	Low pressure feed water system (LP)	Reserve feed water system	▪ Failed to supply make-up water to condenser ▪ Failed to supply surplus water to high level reserve feed water tank ▪ Failed to supply de-mineralized water ▪ Failed to supply water from low feed tank to high level feed tank as required	0.9998
7.6		Water de-mineralization system	▪ Unable to supply water to supply pumps ▪ Pumping system failed to supply water	0.9585
7.7		Chemical supply system (Hydrazine and Ammonia)	▪ Failed to pump ▪ Failed to supply	0.9786
8.	High pressure feed water system (HP)		▪ Feed auxiliaries failed ▪ Failed to pump water to main header ▪ High pressure heaters failed to raise the temperature of water ▪ Failed to supply water ▪ Unable to continue water flow	0.9999
9.	Instrument and service air system		▪ Failed to supply air to the service air tanks ▪ Failed to supply air to instrument air tanks	0.9650

6.2 Consequence analysis

The objective here is to prioritize major systems, subsystems and components on the basis of their contribution to a failure of unit 3. Consequence analysis involves estimation of maintenance cost and production loss cost.

6.2.1 Estimation of maintenance cost

Maintenance cost typically includes the cost of labor and parts and the down time associated with repairs. The maintenance cost is calculated using the mathematical model given below

$$MC= C_f + DT \times C_v$$

Where Cf – Fixed cost of failure (Cost of spare parts), DT – down time, C_v – Variable cost per hour of down time (Labor rate and crew size). **Appendix G** has the details.

A) Cost of spares

The cost of raw material, internally manufactured part, the parts sent away for repairs, spare parts, consumables, small tools, testing equipments, rent for special equipments and special treatments are accounted. The cost of spares and raw materials is drawn from the plant stock book. For small tools $3.00 is added per man-hour. Special equipments rent and other special treatment cost is derived from plant records.

B) Maintenance down time

Down time means the total amount of time the plant would normally be out of service owing to the failure, from the moment it fails until the moment it is fully operational again. The repair process itself can be decomposed into a number of different subtasks and delay times as shown in the Figure 6.6

	Down time						
Plant outage	Maintenance Delay	Access time	Diagnose the fault	Supply Delay	Replacement or repair	Revalidate the equipment	**Put the plant into service**

Fig 6.4 Down time

Maintenance delay time is the time spent waiting for maintenance resources or facilities. It may also include administrative time and travel time. Resources may be personnel, test equipment, tools, and manuals or other technical data. Access time is the amount of time required to gain access to the failed component. In power plants, access time varies depending on the equipment; access to the boiler will be the least. Diagnosis, or troubleshoot, time is the amount of time required to determine the cause of failure. The repair time or replacement time includes only the actual hands-on time to complete the restoration process once the problem has been identified and access to the failed component is obtained. Supply delay consists of the total delay time in obtaining necessary spare parts or components in order to complete the repair process. All of the power plant equipment requires validation before they put into service.

c) Labor rate and crew size

The cost of labor is an important component of the maintenance cost. This is based on the hourly rate for various trades and the information is drawn from the plant documentation.

Table 6.4 Labor rates

Trade	Description	Hourly rate
Boiler maker	General Foreman	$46.21
	Foreman	$44.90
	Fitter/welder	$41.26
	Apprentice 3	$38.04
	Apprentice 2	$32.81
	Apprentice 1	$27.64
	Helper	$38.04
Pipe fitter	Foreman	$45.49
	Welder/Journeyman	$42.64
Mill Wright	Foreman	$41.47
	Welder/Journeyman	$40.22
	Apprentice	$38.60
	Journey	$34.64
	Instrumentcian	$25.00
	Electrician	$25.00

Down time associated with forced outage and forced de-rating state is estimated from the failure data collected in the unit 3. Owing to the lack of data, the down time and the number of maintenance personnel involved in repair is estimated by interviewing the maintenance personnel. **Appendix- E** shows the excel sheet for repair cost estimation details.

6.2.2 Estimation of production loss cost

Asset utilization, a measure of production performance, has become a key manufacturing improvement tool in any production process. Asset utilization is defined as actual production divided by capacity, for any given period of time. The difference between the two constitutes production losses, which is inherent in any manufacturing operation. The details about functional failures that cause production losses are discussed in chapter 4.3. The production loss cost is estimated using the mathematical model given below.

$$PLC = DT \times PL \times SP$$

Where

DT – Down time, PL – Production loss tae in Mega Watt hours, SP – Selling price

The production loss rate in Mega Watt hours is computed from the failure data. The selling price is identified from the plant as \$ 45.00 per Mega Watt hours. The selling price is derived from the cost of the No. 6 Fuel oil (High sulfur residual fuel oil is a heavy oil used by ocean liners and tankers as fuel, and for oil burning power plants) per barrel, combined with the plant overheads. **Appendix G** has the production cost estimation details.

It is evident through the analysis that the functional failures of the system or equipment are due to various failure modes. Also, the system or equipment cannot put back into service until all failures are repaired, in addition, it involves down time. The system or equipment down time varies with the type of failure mode. The system remains in a failed state until the failure mode that utilizes the maximum down time is repaired. For this reason, the failure mode with the maximum down time is selected consequently, the production loss. For example, boiler failed 14 times during 1992- 2002 and the failure has occurred because of different failure modes that caused partial and total failures (the cost of total failure with maximum down time is found as \$3618000).

The combination of production loss cost and the maintenance cost gives the consequence of the failure in dollars. The major systems and equipment are prioritized based on the maximum loss associated with each failure. **Appendix- F** gives the details of consequences and the risk analysis.

6.3 Risk estimation and evaluation

The results of the consequence and the probabilistic failure analysis are then used to estimate the risk of unit 3. Refer to Figure 6.5 for the detailed description. The individual risk for each subsystem is shown in **Appendix- F.**

Risk evaluation is the process by which risks are examined in terms of costs and benefits, and evaluated in terms of acceptability of risk considering the needs, issues and concerns of the unit 3. The acceptance risk criterion is determined based on the yearly maintenance expenditure of unit 3. The acceptable risk criterion for the power plant is $2,000,000 per year. Now, the acceptance criterion is compared with the estimated risk of individual major system. any value higher than this is unacceptable. The major systems whose estimated risk exceeds the acceptance criteria are identified. These are the units that should have an improved maintenance plan. Three major systems steam generator, air and flue gas system and high pressure feed water system did exceed the acceptable risk criteria. This indicates that the risk should be reduced to maintain the continuous operation of unit 3. Considering these factors a new maintenance schedule is developed. The details are discussed in the following section. The algorithm used is shown in Fig.6.7

6.3.1 Risk ranking

As discussed in the previous sections, risk is a direct function of two factors, probability and consequence and represents the co-ordinate axes in a common x-y plot configuration. Every ordered pair of the probability value and its corresponding consequence value, [p,c], represents risk in major system. The risks associated with major systems are then ranked for setting priorities in implementing the risk management strategies. Those, which have unfavorable indicators with respect to acceptable criteria, need action. Fig 6.8 shows the co-ordinate system and risk ranking. Table 6.5 shows the ranking of major systems and the first three systems require maintenance planning.

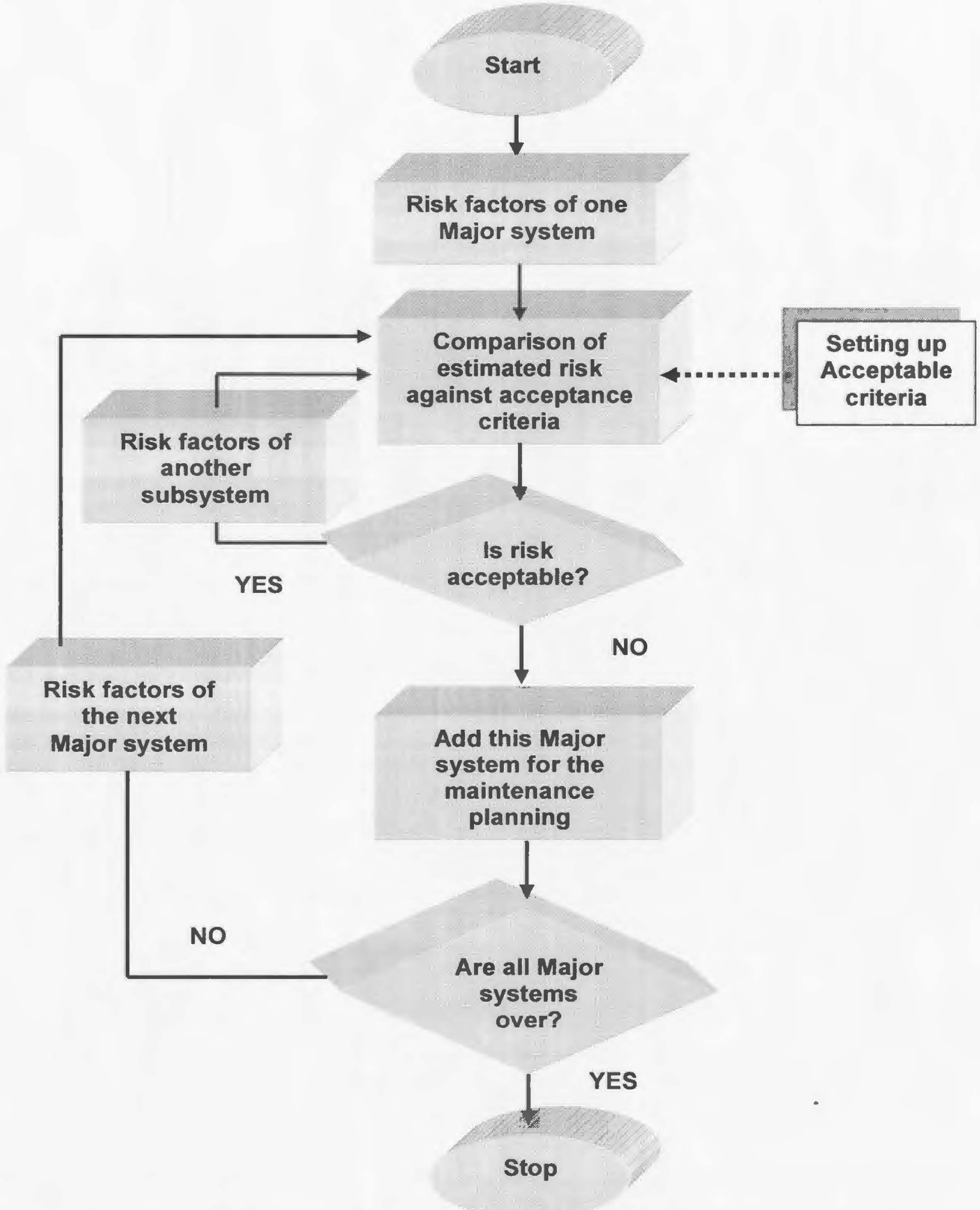


Figure 6.5 Description of risk evaluation module (Ref: Khan and Haddara (2003))

Table 6.5 Top potentially maintainable systems

Rank	Major system	Consequence in millions	Probability of failure (Over 20 years)	Risk ($) (Over 20 years)
1	Steam generator	3678481	0.9989	3,674,435
2	High Pressure feed water system	2478842	0.9999	2,478,594
3	Air and flue gas system	2102023	0.9914	2,083,946
4	Generator	1634060	0.9780	1,598,111
5	Turbine- steam supply	1110574	0.9999	1,110,463
6	Fuel oil system	1110574	0.9866	1,095,692
7	Condenser	874745	0.9939	869,409
8	Turbine rotating system	302053	0.9999	302,023
9	Low pressure feed water system	286584	0.9995	286,441
10	Instrument and service air system	25249	0.9650	24365

6.3.2 Risk Index

The risk index is to evaluate which combinations pose the greatest risk to the failure of unit 3. In essence, the risk index is a filter for finding those risk element–impact–potential cause combinations that have the greatest contribution to the failure. The division of risk and the acceptance criteria gives the risk index. Based on the risk index the subsystems are classified as high risk (above 1), medium (0.4-0.8) and low (below 0.4). Table 6.4 shows the results.

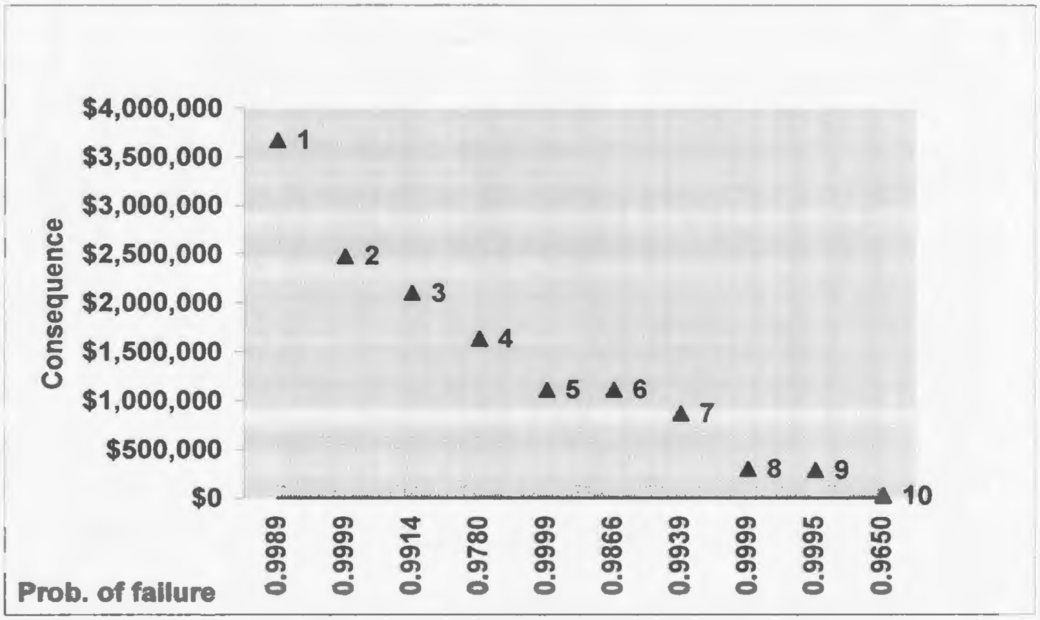


Figure 6.6 Ranking of major systems

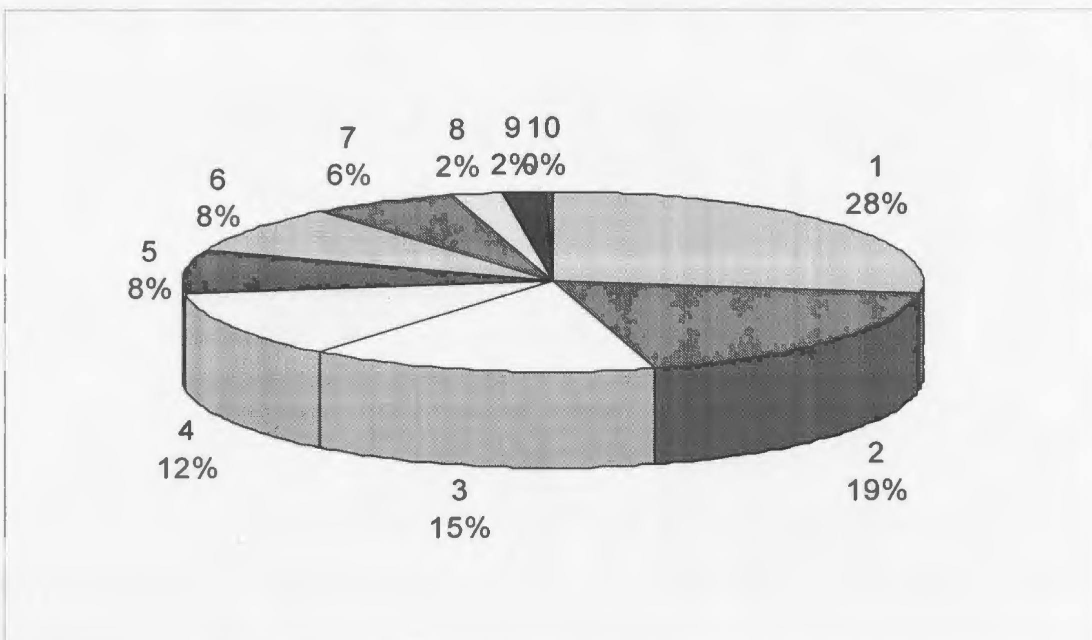


Figure 6. 7 Risk contributions of major systems

Table 6.6 Ranking of subsystems and risk index

S.No	Subsystems	Risk Value $	Risk index	Level of concern
1	Air preheater east	2045058	1.0225	High
2	Forced draft fan east	1444656	0.7278	Medium
3	Forced draft fan west	1333840	0.6669	
4	Heavy oil system	1109352	0.5547	
5	Re-heater	1107242	0.5536	
6	Super heater	1102245	0.5511	
7	Furnace	918590	0.4593	
8	Air preheater west	270734	0.1354	Low
9	Flue gas system	123272	0.0616	
10	Air flow control system west and	108783	0.0544	
11	Air flow control system east	108783	0.0544	
12	Steam air heater west and east	108658	0.0543	
13	Steam air heater west and east	108658	0.0543	
14	Economizer	79781	0.0399	
15	Steam drum	73312	0.0367	
16	Blow down system	32472	0.0162	
17	Vacuum system	19827	0.0099	
18	Water extraction	15374	0.0077	
19	Cooling water supply system	12827	0.0064	
20	Screen wash system	12618	0.0063	
21	Light oil system	11568	0.0058	
22	Fuel additive system	18350	0.0092	
23	Low pressure heater #1	8372	0.0042	
24	Low pressure heater #2	8290	0.0041	
25	Reserve feed water system	7192	0.0036	
26	Gland seal condenser	7165	0.0036	
27	Water demineralization system	6894	0.0034	
28	Condenser back wash	2982	0.0015	
29	Chemical supply system	2338	0.0016	

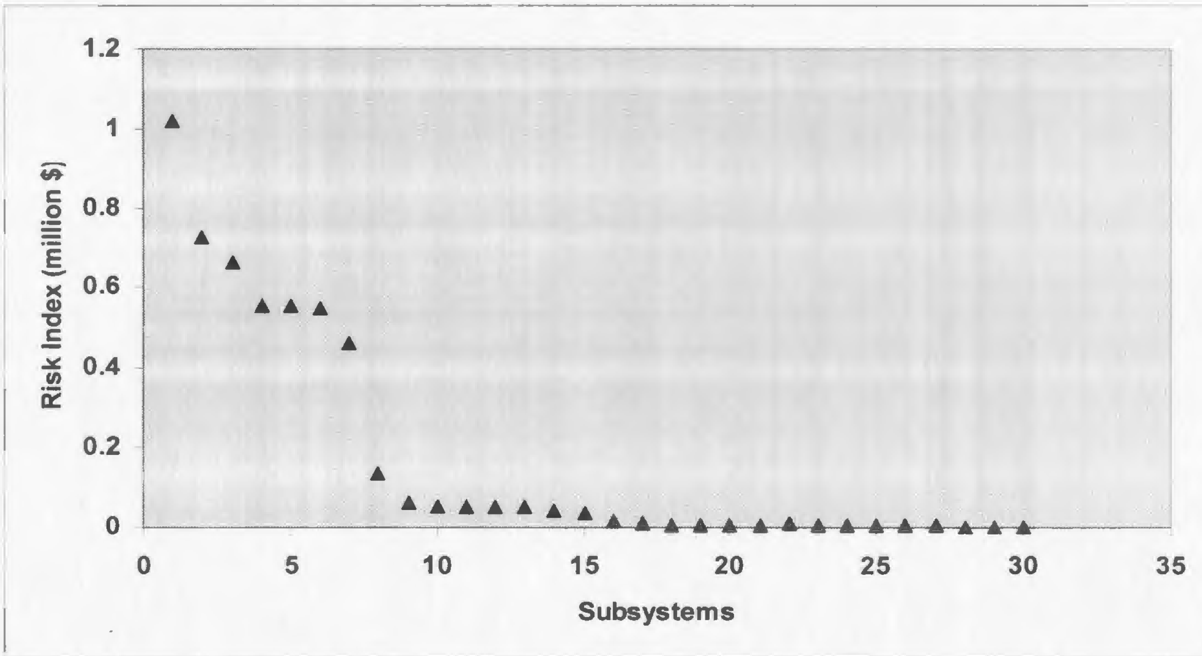


Figure 6.10 Ranking of subsystems

6.4 Maintenance Planning

An effective maintenance and inspection plan is developed for each major system and subsystem that exceeds the acceptance risk level. Reducing the probability of failure and combining the consequences further reduce the three major systems with unacceptable risk to an acceptable level. The assigned or new probability value is used as the target probability of the failure scenario. Table 6.4 shows the target probability values and risk reduction results. Based on the target probability of the top event a reverse fault tree analysis is performed to find the target probability of basic events. **Appendix- G** shows the Matlab program to find the target probability of basic events.

Table 6.7 Risk Reduction results

S.No	Major system	Consequence Scenario in $ (Over 20 years)	Probability of failure in 20 years	Risk factor ($) (over 20 years)	Target probability	Risk reduction in Dollars
1	Steam generator	3,678,481	0.9989	3,674,434	0.54	1,984,194
2	Air and flue gas system	2,102,023	0.9914	2,083,945	0.85	1,771,353
3	HP feed water System	2,478,842	0.9999	2,478,594	0.80	1,982,875

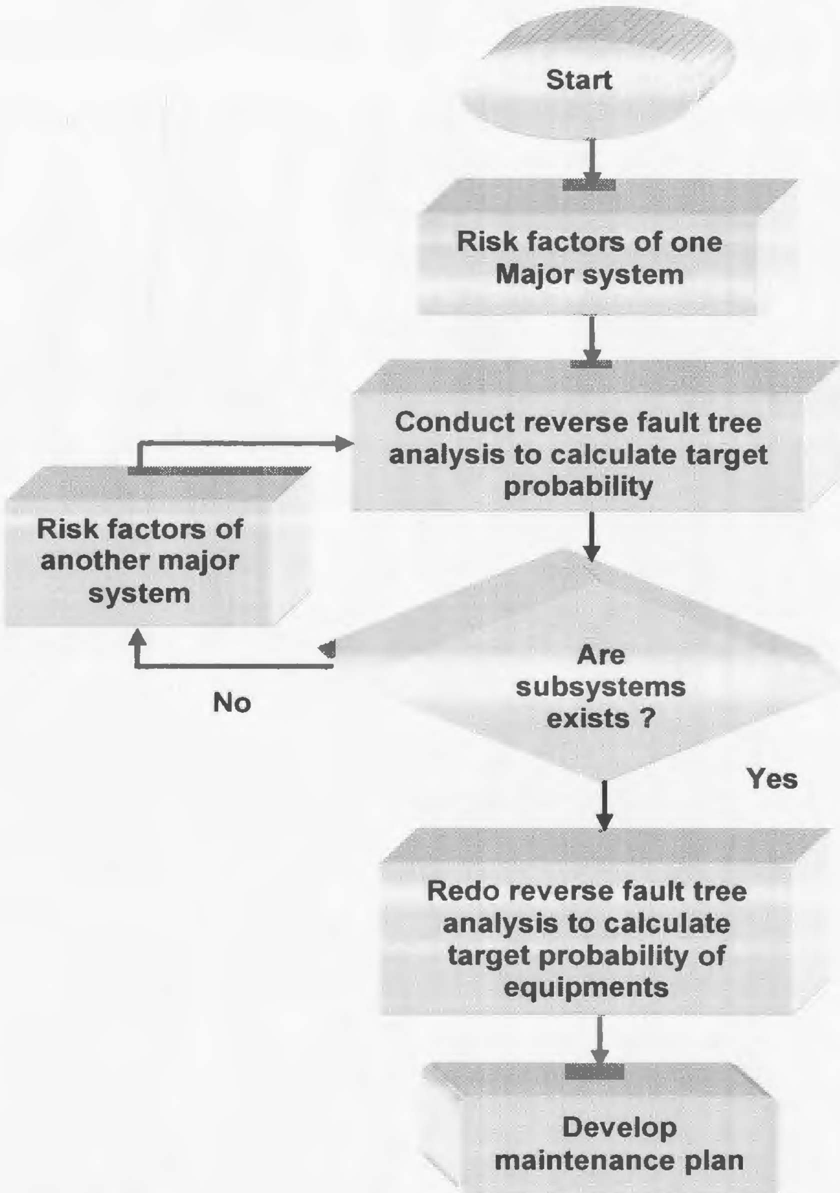


Figure 6.11 Description of maintenance planning module (Ref: Khan and Haddara (2003))

After re-arranging the failure functions and using the failure parameters a new value for the maintenance interval is calculated. Thus, the reverse fault tree analysis gives the optimal times at which maintenance/inspection is to be performed.

Exponential failure probability function F (t) = $\int_{-\infty}^{t} f(t)dt = 1 - e^{-\lambda t}$

Maintenance interval t = $-\left(\dfrac{\ln(1-F(t)}{\lambda}\right)$

Weibull failure probability function F (t) = $\int_{-\infty}^{t} f(t)dt = 1 - e^{-(t/\theta)^{\beta}}$

Maintenance interval t = $\left(-\ln(1-F(t) \times (\theta)^{\beta}\right)^{1/\beta}$

The calculated maintenance interval is modified based on the system complexity and access to maintenance. The maintenance schedule for the three subsystems of unit 3 is given in Table 6.8

Table 6.8 Unit 3 Maintenance schedule

S.NO	Major system /Sub system	Components	Calculated Maintenance Interval in days	Modified Maintenance Interval
1.	Steam generator	Boiler	298	1 year
		Furnace		1 year
		Economizer		1 year
		Steam drum		1 year
		Super heater		1 year
		Re-heater		1 year
		Water walls	393	1 year
		Blow down system		1 year
		Chemical supply system		1 year
		Auxiliary steam supply system	223	1 year
1.1	Furnace	Igniter	90	3 months
		Burners	174	6 months
		Retractable soot blowers	84	3 months
		Rotary soot blowers	84	3 months
		Cleaning of ash	84	1 year
		Manual door in furnace	135	6 months
		Refractory lining in furnace door	152	6 months
1.2	Econo -mizer	Economizer tubes	380	1 year
		Water supply header	2501	7 years
		Vent valve	266	1 year
		Globe valve	219	1 year
		Cleaning of excessive scaling	21	1 year

S.NO	Major system /Sub system	Components	Calculated Maintenance Interval in days	Modified Maintenance Interval
1.3	Steam drum	Cyclone separator	109	6 months
		Feed water control system	555	2 years
		Level Indicating Transmitters (LIT)	119	6 months
		Steam drum	145	6 months
		Clogged Down comer nozzles	116	6 months
		Worn gaskets and leakage	174	6 months
		Safety valves	152	6 months
		Plate dryers	89	6 months
		Liners	152	6 months
1.4	Super heater	Secondary Super heater (SS)	175	1year
		Primary Super heater (PS)	175	1year
		SS inlet and outlet headers	4167	10 years
		PS inlet and outlet headers	4167	10 years
		Safety valves	47	3 months
		Temperature indicating transmitters	102	6 months
		Steam and control system	77	3 months
		Attemperator	4167	1 year
		Control valve	101	3 months
		Pressure indicating transmitters	123	6 months
		Boiler control	79	3 months
		Combustion control	32	3 months
		Fuel oil management and control	253	1year
		Spray nozzle	103	1year
		Globe valve	106	6 months
		By pass valve	120	6 months
1.5	Re-heater	Primary re-heater	37	1 year
		Re-heater inlet and outlet headers	41669	10 years
		Secondary re-heater	37	1 year
		Control system (Attemperator)	59	6 months
		Control valve	73	3 months
		Nozzle	71	6 months
		Globe valve	76	6 months
		By-pass valve	86	6 months
		TIT's	74	6 months
1.6	Blow down tank	Globe valve (Steam drum)	631	2 years
		Angle valve (Steam drum)	13	2 years
		Control valve	82	3 months
		Check valve	106	6 months
		Level switch	29	6 months
		By pass valve	49	6 months
		Blow down tanks	101	6 months
		Water seal	786	2 years
		Motorized valve (Individual system blow down)	71	3 months
		Globe valve (Individual system blow down)	60	3 months

S.NO	Major system /Sub system	Components	Calculated Maintenance Interval in days	Modified Maintenance Interval
1.7	Chemical supply system	Chemical supply pumps 1&2	103	3 months
		Ball valves	127	6 months
		Chemical supply pump Motors	80	3 months
		Strainers	112	6 months
		Safety valves	129	6 months
		Globe valve	120	6 months
		Check valve	43	6 months
2.	Air and flue gas system	Forced draft system west		3 months
		Steam air heater system west		1 year
		Air preheater system west		3 months
		Air flow system control west		3 months
		Forced draft system east		3 months
		Steam air heater system east		1 year
		Air preheater system east		3 months
		Air flow control system east		3 months
		Air foil east		3 months
		Air foil west		3 months
		Flue gas system		1 year
2.1	Forced draft fan west and east	Force draft fan west (F.D)	144	3 months
		F.D.fan motor west	22	3 months
		Furnace draft control	48	6 months
		Inlet guide van drive	182	6 months
		PIT	179	6 months
		Combustion control	47	2 months
		Inlet, outlet dampers	187	6 months
		Inlet, outlet damper drive	182	6 months
		Controller	48	2 months
		Timer	211	1 year
		Relay	535	1 year
		F.D fan east	44	3 months
		F.D fan motor east	60	3 months
2.2	Steam air heater	Globe valve	324	1 year
		Control valve	320	1 year
		Com. and gas control	388	1 year
		Gate valves	435	1 year
		Tubes Inspection	364	1 year
		Cleaning of fins	588	1 year
2.3	Air pre heater	Air pre-heater (A.H) west	154	3 months
		A.H west drive motor	217	3 months
		Basket seals	365	1 year
		Plugged hot basket cleaning	200	1 year
		Ducts inspection	109	1 year
		A.H east	118	3 months
		A.H motor east	217	3 months

S.NO	Major system /Sub system	Components	Calculated Maintenance Interval in days	Modified Maintenance Interval
2.4	Air flow control system	Flow indicating transmitters (FIT)	157	6 months
		Flow Indicators	517	1 year
		TIT's	157	6 months
		Flow control systems (FCS)	175	6 months
		Dampers	2403	3 years
		Damper drives	196	3 months
2.5	Flue gas system	Cleaning of slag built up	208	1 year
		Oxygen analyzers	384	1 year
		Inspection of ducts	109	1 year
		Lining	4037	10 years
3.	High pressure feed water system	Feed auxiliaries	480	1 year
		Feed water supply pump #1	246	1 year
		Gland sealing	472	1 year
		Gate valve	809	1 year
		Feed water pump drive motor	562	1 year
		Feed water supply pump #2	311	1 year
		Feed water pump drive motor	562	1 year
		HP heater #4	55	1 year
		HP heater #5	843	2 years
		HP heater #6	480	1 year
		Feed water heater Ins.& Con.	480	1 year
		De-aerator	579	1 year
		Feed water piping and support	39	1 year

Chapter 7 Findings and Conclusion

A) Findings

The following are the findings of Unit 3 based on the risk analysis.

- The risk that exists in Unit 3 is calculated for 20 years
- Three major systems steam generator, high pressure feed water system, and air and flue gas system have fall under high-risk category (the calculated risk of more than $2,000,000 is considered as high-risk and is unacceptable). These three major systems contribute 62% of overall risk of power plant (Refer section 6.3.1)
- The study of failure patterns of equipments based on the failure data collected from the plant shows that 18% of the equipments conformed to pattern B, 9% to C and the remaining 73% to D (Refer section 5.8)
- The analysis of failure pattern of Burners, Boiler control, Condenser tubes, Boiler feed pump # 2, HP heater # 5 and Boiler feed water Ins & control shown that, failures have occurred in the wear out region.
- The analysis of failure pattern in Boiler, Water walls, FD fan #1, and Boiler feed pump #1 shows that the failures occur due to random loads or chance events. Preventive maintenance has no effect on these equipments.
- Based on risk index, subsystems are classified as high, medium and low risk. Air-preheater has high risk (Refer section 6.3.2)
- The inspection time of furnace, economizer, super heater. re-heater, and water walls remains the same, as the opening of steam generator is associated with longer down time. and cost. Moreover the plant is not operated through out the year
- A revised maintenance interval is suggested for components in furnace, economizer, super heater, re-heater and water walls. These subsystems play a major role in determining the operational life of steam generator. Refer Table 6.8 Unit 3 Maintenance Schedule

- The maintenance interval for HP feed water system is fixed as one year. However, feed auxiliaries, feed water pumps, motors, control systems require frequent inspection.
- The maintenance interval for the subsystems with acceptable risk remains the same. However, all the transmitters, flow indicators, required calibration once in 6 months. Moreover, safety valves, and control valves needs inspection once in 3 months instead of one year to improve overall efficiency and to ensure trouble free operation.
- Non Destructive Testing (NDT) inspection frequency remains the same for all pipe lines, drains and tanks.

B) Conclusion

Today, power plants have achieved some level of success using a conventional maintenance process and use a Computerized Maintenance Management System or CMMS to efficiently execute maintenance work – but is that work too much too soon or tool little too late?

When discussing about the Today's challenges, equipments become increasingly complex. The risk and consequence of equipment failure is significant and can be devastating to the business. Stringent safety and environmental regulations, if not met, can result in significant fines. Further the success of the power plants is dependent on the condition, availability and reliability of plant assets.

So, to ensure that doing right work on the right equipment at the right time to optimize asset reliability, we need a more comprehensive process. Risk Based Maintenance methodology, discussed in the previous chapters ensured a structured approach to solve the today's problems and challenges

To conclude, the strategy based on risk analysis has provided to develop a cost effective maintenance strategy, which minimizes the economic consequences of a system outage/failure, and help the management in making right decision concerning investment in maintenance or related field. This will, in turn, results in better asset and capital utilization.

Chapter 8 Recommendations

This chapter presents the recommendations of this study based on the application of Risk Based Maintenance policy to Unit 3.

The five major parameters operation, maintenance, design, management and construction of the plant have major impact on the production cost. Moreover, if the design and operation is poor, maintenance has no impact on plant performance.

The failure pattern suggested that in 73% of equipments a failure occurs during useful life (random failures). The causes are random loads, human error, and chance events. An analysis of operating conditions of the equipment needs to be done to find out the reasons behind their premature failure.

The failure pattern suggested that in 23% of the equipments a failure occurs in the wear out zone, which is very good sign. The implementations of predictive maintenance techniques will enhance the life of these equipments and reduce the cost of maintenance

Fault tree models developed based on the system flow charts are the visual models of the individual system and less time consuming. This is the most effective method that brings up all the functional failures and hidden failures. Also, it can be possible to predict the likelihood of failures. This aids in redesigning of existing system if necessary or helps in improving the reliability of individual system.

Equipments and systems are prioritized based on risk, so that the resources can be focused on the high-risk areas first, simultaneously medium risk and low risk. Careful selection and execution of optimal mix of condition based actions, other time or cycle based actions or run to failure approach will help to bring down the risk of failure in future.

The failure data collected from the plant has various uncertainties. Failure history data may include parts (failed components), operating conditions at the time of failure, and operators (who were they, where were they, what did they see, hear, feel or smell prior and after the incident). The data bank will be very useful to predict the changes in failure parameters in future.

Separate data bank is required to collect the maintenance cost, spare parts cost and other indirect expenses incurred during failure.

The analysis shows that most failures happen more than once in a season, this is called chronic failures. A Root Cause Failure Analysis or RCFA is helpful in finding out why a particular failure or problem exists and correcting those causes.

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Appendix – A Description of Major systems

1. Air and Flue Gas system

The purpose of the air and flue gas system is to preheat the inlet air supplied for combustion. This is accomplished through recovering the heat from the flue gases. The hot air is used to increase the boiler efficiency as well as to improve the combustion efficiency. The entire system consists of forced draft fans, steam heaters and air pre heaters connected through ductwork. The ductwork has a combustion air intake system, a forced drat fan (F.D) fan discharge air outlets to steam coil air heaters. steam coil air heater outlets to regenerative air heater inlets, regenerative air heater outlets to wind box, an economizer outlets to regenerative air heater inlet and regenerative air heater outlet to stack inlet. The flues and ducts are generally of all welded construction using steel. Flexible metal expansion joints are installed where it is required to give adequate support and the guides are included to eliminate transverse loading of flexible expansion joints. **[Refer to Flow Diagram 4.6]**

Dampers are installed in the air inlet and the outlet to the F.D fans to control the airflow. They are of the narrow multi-louvre type. Power operators are provided on the F.D fan discharge dampers and on the six sets of combustion air control dampers. Manual isolating dampers are fitted to the air and gas outlets of the air pre-heaters.

The soot hoppers are located in the gas flues before and after the air pre heaters. The hoppers are equipped with flanged outlets for soot disposal.

The two runs of ductwork upstream of the wind box in the east and west sides of the steam generator are each divided into three so that separate combustion air supplies are routed to the three horizontal levels of the burners. The airflow for each level of burners is measured by two airfoil-measuring elements and is automatically regulated by two control dampers.

The air is drawn either from outdoors or from a combination of the two sources. Individual intakes and supply ducts are provided for each forced draft fan. The intake dampers are operated by pneumatic drives from remote manual station located at the operating level.

1.1 Forced draft fans

The two fifty percent capacity centrifugal force draft fans are installed for parallel operation. That includes variable inlet control vanes; outlet louver dampers and flexible drive couplings. The fans are directly coupled to 1500 hp, 1190 r.p.m electric motor drives. The fan wheels have ten backward inclined airfoil blades. The discharge pressure of each fan is automatically controlled, the pressure being indexed to the load on the steam generator. The discharge pressure is regulated by modulation of the fan inlet vanes.

The ducts on the outlets of the F.D fans downstream of the outlet dampers are interconnected. This permits single fan operation with air flowing through both air per heater and being distributed to both ends of the wind box. In the same manner, the combustion air ducts are interconnected to the downstream of the air pre heaters.

1.2 Steam Coil air Heaters

Steam air heaters are provided to limit air heater cold end corrosion, fouling and to preheat combustion air the flue gas air heaters can be put into service. The steam coil air heater is fitted in the air duct upstream of each main air pre heater. It consists of circular tubes with extended steel fins, through which the bled steam passes. The arrangement is similar to the radiator The heater raises the temperature of the air entering the main air pre heater. The condensate disposal unit consists of steam traps, strainers and by-pass valves. The amount of steam fed to the steam coils is automatically regulated and is a function of the arithmetic mean of the sum of the main air pre heater gas outlet temperature and air inlet temperature.

The steam coil air heaters are designed to maintain the flue gas outlet temperature at up to 350 F. corrected for leakage, over the full load range. with an air inlet temperature to the steam coils of -7°C (20°F).

1.3 Air pre heater (A.H)

The air pre heaters are used to recover heat from flue gases at temperatures lower than that is economically possible with economizers. It is also helpful to increase the boiler efficiency. Two continuous regenerative air pre heaters are fitted and operate in parallel. Regenerative means the gas flows through a closely packed matrix with consequent increase in matrix temperature and subsequently air is passed through the matrix to pick the heat. They are of the vertical flow design with the air for combustion entering at the bottom, passing upward through the heating surfaces and discharging at the top into the hot air ducts. The hot flue gas enters at the top. and counter flows to the air and exhausts down wards by natural draft to the stack.

The mild steel rotor is the central part of the air heater and contains the heat transfer matrix. Radial plates extending from the hub divide the rotor into 24 sectors, which in turn are subdivided at the hot and intermediate end element containers. At the cold end of the rotor, grids welded between the radial divisions allow the sideways removal of the cold end elements without disturbing the upper tiers. The weight of the rotor is carried on the underside by a spherical roller thrust bearing, whilst at the top, radial loads are resisted by a spherical roller guide bearing.

The heating surface area of each air pre heater is 4534 m^2 made up of two layers of heating elements. The hot end layer is 81.28 cm and cold end layer is 30.48 cm and the latter being made of corrosion resistant enameled steel. The cold end layer is mounted on baskets for side removal.

1.4 Air flow control system

This system controls the airflow and integrated with boiler master control, combustion control, firing ration control and forced draft damper control systems.

1.5 Flue gas system

Oil and air after combustion with in the furnace reaches the chimney through ducts. Heat is extracted from the gases in various stages. The outlet temperature of the heat recovery steam generator is limited to 140 °C to avoid low-temperature corrosion. During combustion the major constituents of the oil are converted to carbon dioxide, and water vapour, nitrogen and oxygen.

2. Fuel oil system

A fuel oil system is used to supply heavy oil for burning and the whole system is designed to serve the following purposes. 1. To keep the oil in the storage tanks at a temperature at which it will flow by gravity into the transfer pump. 2. To raise the oil to a temperature which will give a viscosity that is suitable for atomizing into a spray at the burners. 3. To raise the pressure of the oil to that necessary to give efficient burner atomization over a specified load range. It has the following subsystems: heavy oil system, light oil system and fuel additive system.

2.1 Heavy oil system

This system provides and prepares the heavy oil for burning in the boiler furnace. The oil is drawn from the fuel oil storage tank farm. The oil is drawn through the suction header and transmitted to the day tank. It is fed from the day tank farm to the day tank by gravity. It is then drawn from the day tank, heated to the required temperature by the unit pumping and heating equipment for atomizing and burning, and discharged at a constant pressure and temperature to the unit main fuel oil burner header. **[Refer to flow diagram 4.7]**

2.1.1 Fuel oil forwarding system

The fuel oil is transferred to the oil tanks through pipelines from the ship this is called the fuel oil transfer system. The two oil tanks located in the farm have the same capacity of 33,710 m^3 each. Each storage tank has two suction heaters for raising the temperature of the oil as it is discharged from the tank. The heating medium is low-pressure steam from the auxiliary steam system. A self-contained temperature-regulating valve is provided with each suction heater. This is installed in the heater steam supply line with the temperature-sensing bulb located in the heater oil outlet piping. A steam trap on the steam outlet from the suction heater discharges the condensate to waste.

In addition, two immersion-type steam heaters are provided for adding heat to the oil stored in the tank. The steam flow is regulated manually and, as with the suction heaters, the condensate is discharged through traps to waste. The oil supply to the day tank after raising the temperature is called the fuel oil forwarding system. Oil level transmitters are installed for local and remote monitoring of the oil level in the tank.

2.1.2 Fuel oil supply system from day tank to burners

The fuel oil flows by gravity to the inlets of the fuel oil supply pumps on each unit. The fuel oil consumption in unit three is 10.08 kg/s. The two one hundred capacity positive displacement type fuel pumps are provided, each having a duplex basket strainer fitted to its suction piping. A differential pressure switch to alert the control room operator to abnormally high conditions monitors the pressure drop across the strainers. The suction oil temperature is indicated locally and inputted to the data logger. A by-pass is provided for uninterrupted oil supply. The discharge pressure is maintained at approximately 2068 kPa by pneumatic backpressure control system, which returns excess oil to the day tank. A pressure relief valve is fitted to the discharge piping of each fuel pump, upstream of the isolating valve, to prevent over pressuring. The temperature of the oil leaving the fuel oil heaters is 99° C and the viscosity will normally be between 125 and 130 SSU. Both viscosity and temperature are required for correct operation of oil burners; it is measured and controlled using a controller system.

Two arrangements have been provided under the control of the burner automation system for re-circulating oil to bring the piping systems up to operating temperature. The main supply route returns the oil to the day tank from the point on the 4" supply header immediately upstream of the main fuel oil trip valve FV-3292 through the re-circulation valve FV-3292. FV-3292 closes when FV-3281 is opened and opens when FV-3281 is closed. Upon opening FV-3281, the fuel oil flows to the headers at the three horizontal levels of burners through the minimum header pressure valves FV- 3200 A, B and C up to the inlets of the header level trip valves BV-3200 A, B and C. The opening of any of these header trip valves will automatically open their associated header re-circulation valve (FV-3250 A, B and C) allowing oil to flow through the header and return to the fuel oil day tank. The quantity of oil re-circulated from each level header is regulated at approximately 0.63 kg/s by an orifice plate (FO-3200A, B and C), located on the discharge of the header re-circulation. The valve automatically closes upon the successful lighting of the first burner on that level.

The steam generator has nine burners mounted on the front wall of the furnace section. The burners are arranged in three levels of three and the control of the reheat steam temperature is obtained by rationing the heat input to the furnace between these three levels of burners. This requires separate combustion control equipment for each oil supply level header, the equipment for each level being identical. This consists of a fuel oil supply control valve (FV-3200A, B or C), with a minimum pressure control valve (FV- 3200A, B or C) piped in parallel, and a positive displacement type flow transmitter (FIT-3200A, B or C). A drain is piped from the body of the transmitter, before the internal flow measuring components, to prevent build up sediment. The drain valve is normally cracked open.

The minimum pressure regulator (PV-3200A, B or C) on each level header is a local pneumatic control loop with the pressure control mounted on the control valve. The controller is set to maintain the pressure downstream of the control valves FV-3200A, B or C at a minimum of 358kPa approximately, with all burners on the level lit. The final pressure setting is to be determined in the field to suit proper oil burner operation. The automatic burner control system provides for safe, remote operation and management of the oil burners and the associated equipment. The system is electronic but utilizes pneumatic actuators on the fuel oil trip and burner valves. These valves are two position types being either fully closed or fully open. Two limit switches are fitted to each valve to monitor closed and open positions.

A hydraulic accumulator is installed in the main fuel oil supply header upstream of the main trip valve to prevent unacceptably high pressure surges in the upstream piping and equipment when this valve trips to the closed position.

2.2 Light oil system

The light oil system has been furnished to permit lighting of the system generator from a black start when atomizing steam is not available for firing with no.6 fuel oil. The light oil is piped to the bottom level of three burners only. The air is supplied from the service air system and is used in the burners as the atomizing medium and as purging on burners during shutdown, when steam is rising with light oil. The light oil for unit three is supplied from the existing light oil storage tank: the supply piping is connected in parallel to the suctions of the oil pumps for unit three and other units. The connection for unit three is taken form the unit two light oil suction header and is a 2" diameter pipe. **[Refer to flow diagram 4.8]**

The light oil pumping set consists of two one hundred capacity positive displacement pumps, each which is fitted with a simplex basket strainer. A safety relief valve is fitted to the discharge of each pump to prevent damage by overpressure. The discharged oil returns to the light oil storage tank. A check valve is also furnished at the discharge from each pump to prevent back flow through the stand-by pump when the isolating valve is open. The discharge pressure from the pump is held at a nominal 1034 kPa by a self contained back pressure regulating valve PCV-3324 which relieves excess pressure by draining oil back to the light oil storage tank. The stand by pump is started automatically if the running pump is unable to maintain the discharge header pressure. Pressure gauges are fitted at the inlet and outlet of each simplex basket strainer, at each pump discharge and on the common discharge header. A 1" supply header connects the pumping set discharge to the bottom level of three burners. An automatic trip valve BV-3341 and a remote manually operated control valve FV-3343 are installed in the header. The control room operator uses the control valve to regulate the flow of oil. An indication of header pressure is provided to assist the operator making adjustments. A 1" re-circulation line routes the light oil form the header at the burner front back to the light oil storage tank. Isolation is performed by the manually operated gate valve LF-V513 that must be closed when the burners are operating on light oil

2.3 Fuel additive system

There are three distinct problems in steam boilers from the use of fuels containing high levels of contaminants and sulfur such as the following: super heater and water wall deposits and corrosion, cold end corrosion from sulfuric acid, and emissions. Deposits on the super heater tubes and water walls are derived from vanadium, lead, sodium and calcium in the fuel. These deposits can be modified and/or eliminated by treatment with magnesium oxide or magnesium hydroxide slurries. **[Refer to flow diagram 4.9]**

The system has a storage tank, positive displacement pump and interconnecting piping. The pumps are pneumatically controlled. The control signal to each pump is the total heavy fuel oil flow to the burners of the associated steam generator. The pump is therefore set up to proportion the correct amount of additive at all steam generator operating loads. The unit has separate regulating systems and fuel oil supply headers for each of the three horizontal levels of burners. The additive is piped to each header immediately upstream of the header trip valve. A manual isolating valve is installed on the additive piping at the connection to the fuel oil supply header. A check valve is also fitted to prevent heavy fuel oil from entering the additive system.

2.4 Firing ratio control system

The firing ratio control system distributes the master demand signal from the boiler master to the individual burner elevations in the proportions determined by the reheat demand signal. Maximum and minimum fuel flow limits determined by the number of burners in service prevent the demand of the burners from exceeding their capacities.

2.5 Fuel oil temperature control

The fuel oil temperature control system provides for proportional plus integral control of the fuel oil temperature. The set point is adjustable form the miscellaneous instruments panel. Temperature control accuracy is improved by indexing the loop to the fuel oil total flow signal from the combustion control system. Controlling the steam supply to the fuel oil heater coil controls fuel oil temperature. Provision is also made for measuring and indicating the fuel oil viscosity.

2.6 Burner management

The function of burner management is to start up and shut down burners as required as a function of boiler load.

3 Turbine

The steam turbine generator changes the stored thermal energy of steam into kinetic energy and then into electrical energy. Thermal energy is changed into kinetic energy by expanding the steam through stationary nozzle vanes and rotating blades in the High Pressure (HP), Intermediate Pressure (IP), and Low-Pressure (LP) turbines. The stationary nozzle vanes direct and turn the steam into rotating blades so that the rotating blades develop a torque on the turbine shaft.

Super heated and re-heat steam temperature is 538° C for the oil fired plant, on account of the increased risk of super heater and re-heater corrosion, that can occur with oil firing. Steam temperature is limited for reasons for both boiler and turbine design; above 566° C, a rapid fall off in the creep strength of ferrite steels occurs, together with increased oxidation and sealing.

As the speed or rotation is fixed by the electrical frequency, the highest possible speed with electrical system is 60 rotations/second (3600 rotations/minute). The Unit 3 Hitachi turbine uses one double flow HP turbine, one double flow IP turbine and one double flow LP turbine to supply the torque needed to drive the exciter generator system. During normal operation, two forces are exerted on the rotor by the expansion of steam through the turbine blading. One force produces the torque to turn the rotor; the other forces exert axial thrust on the rotor. The axial thrust is essentially balance by opposing sections of blading. The unbalanced portion of the thrust is restrained by the thrust bearing.

The generator consists of a rotating field winding that develops a strong magnetic field, and a stationary armature winding in which the output power is produced. Since the magnetic field is rotating, it causes alternating current (AC) voltage to be induced into three phase winding of the generator stator. When current is drawn from the generator stator, magnetic forces within the generator provide a braking action or drag on the generator rotor. This drag counteracts and absorbs the rotational torque produced by the turbine. In this way, the torque of the turbine is converted into the electrical power.

The brush less exciter at one end of the rotating system supplies field current. or excitation for the generator. Kinetic energy from the rotor is changed to electrical energy by a permanent magnet generator The regulator uses this electrical energy to supply current to the stationary field of the exciter. The exciter is an AC electrical generator whose output can be controlled by adjusting the field current supplied. The rotating armature of the exciter takes energy from the rotating shaft and supplies AC electrical power to a rotating rectifier. The rectifier changes the AC power to direct current (DC) power. The DC power is applied to the field winding of the generator through conductors in the center of the rotors.

3.1 Main steam, re-heat and turbine drain system

Main steam from the boiler super heater outlet is fed to the turbine via the main steam piping system turbine stop and control valves (governor) valves. The superheated steam after expanding through the high-pressure turbine is returned to the re-heater section through the cold re-heat piping system. The steam is re-heated again in the re-heater section and returned to the intermediate pressure section of the turbine through the hot reheat piping system and combined reheat stop and intercept valves. Expansion continues uninterrupted through the intermediate pressure section and the low-pressure section turbines before finally exhausting into the condenser.

The turbine normally requires a constant pressure of 12,410 kPa at the control valves at a maximum steam temperature of 538°C. Main steam temperature is controlled within the boiler by means of spray attemperation between the primary and secondary super heater. The 538°C full steam temperature cannot be attained under normal conditions until the load on the unit reaches approximately 75% of the steam. The steam temperature is regulated to give a maximum of 540.6°C at both super heater and re-heater outlets. **[Refer to flow diagram 4.10]**

The boiler combustion control system controls the firing rate to maintain a constant pressure of 12,410 kPa at the throttle, the pressure being sensed by a pressure transmitter on the main steam pipe to each turbine stop valve. Steam exhausting from the high-pressure turbine is at a temperature of 316°C to 371°C and returns to the boiler to be reheated to 538°C before passing to the intermediate pressure turbine. Reheat steam temperature is controlled by variable rate firing on the three burner levels, and in emergency by spray attemperation, a pipeline spray attemperator is located in the cold re-heat piping for this purpose.

A motorized boiler stop valve is utilized in the main steam piping for isolating the boiler during steam rising or for emergency use and can be operated from either the control room or locally at the valve. The stop valve is furnished with a motorized by-pass, which is opened to facilitate main steam pipe warming and to reduce pressure differential across the stop valve when opened. A 2" main steam pipe drain with tandem manual drain valve is provided immediately upstream of the boiler stop valve and discharges to the boiler blow down tank. Downstream of the boiler stop valve, three drain lines are provided at low points in the main steam piping system. One 2" drain line located immediately downstream of the stop valve is fitted with tandem valves and drains can be directed to either the boiler blow down tank or the start-up de-super heater, each line being fitted with motorized isolating valves. The other pair of drain lines drains the main steam legs before the turbine stop valves. These drain lines are similarly equipped with tandem drain vales, one being motorized. One additional 2" connection is provided downstream of the boiler stop valve which facilitates a supply of live steam to the turbine gland steam regulator during start-up or emergency make-up conditions. Draining to the boiler blow down tank means that the condensate is lost to the station drain. Draining to the start-up de-super heater permits recovery of the condensate by cooling of the steam and subsequent condensation of the drains in the condenser.

Drains are also provided above and below the turbine main steam stop valve seats. The above seat drain from each of the two stop vales is attached to the common pipe beyond the tandem drain valves in each line and led to the boiler blow down tank. The below seat drains are similarly attached to the common pipe after the drain vales but are run to the condenser flash tank. The vacuum in the flash tank provides the pressure differential necessary to ensure adequate blowing of the below seat drains at turbine start-up.

Piping drains are also provided on the cold reheat piping at the lowest point. These drains are led to the condenser flash tank through the orifice plates. The two turbines reheat combined stop and intercept valves are likewise fitted with above and below seat drains. The above seat drains which act as hot reheat piping drain points are led to the condenser flash tank via orifice plates. The below seat drains similarly are fed to the condenser flash tank but without the need for orifice plates. All motorized drain valves in the main steam and hot and cold re-heat piping are normally controlled from the central control room desk but local electrical or manual operation is also provided.

Although the turbine leak-off steam blow down valve is automatically operated as a feature of the turbine protection system it is appropriate that reference be made to it in this section as an item in the turbine drains system. The blow down valve is provided to prevent possible over speeding of the turbine when venting the gland space between the high pressure and intermediate pressure turbine trips unit. When a turbine trip is initiated, the valve exhaust is directed to the condenser and is operate automatically. The gland space is vented rapidly by this method and the small quantity of steam, although at high temperature, causes no distress to the condenser.

3.2 Rotating system

The turbine generator has three large rotating shafts, and a small extension shaft at the governor end. The rotating parts are bolted together with solid couplings to form a single rotating system. There are totally six bearings supports the rotor, five journal bearings and, one thrust bearing.

Two journal bearings support the HP and IP rotors. The other two supports the LP rotor. One thrust bearing is in between the HP, IP and LP turbines supports the rotating system within the turbine casings in the axial direction. The axial expansion of the rotor system takes place from the thrust bearing and extends towards the generator end and towards governor end of the system. The generator contains two bearings one at the turbine end and the other at the collector end. The major components on the exciter rotor are the permanent magnets, the armature of the AC exciter and a rotating rectifier wheel.

3.2.1 Turbine rotor

The rotor body is made from a solid alloy steel forging. Each rotor body is machined carefully to form a solid rotor composed of shaft, wheels, bearing journals and coupling flange. The formed wheels are machined to receive the dovetails of the buckets.

3.2.2 Moving blades

The moving blades are made from a chrome-iron alloy that is extremely resistant to corrosion and erosion by steam. They are machined from bar stock and are dovetailed to the wheel rims by a tight machine fit. Nozzle partitions are machined from a solid chrome-iron alloy and are incorporated into the diaphragm by either a welding or a cast-in process. In the high-pressure end of the turbine, welded type nozzle diaphragms are used. In the low-pressure end cast in type diaphragms are used.

3.2.3 Bearings

The main bearings are of self-aligning type, spherical seated, and pressure lubricated. The bearing casings are made from cast iron or cast steel and are lined with high grade, tin-base babbit. Seals are provided to prevent oil or vapor entering into the bearing.

The axial portion of the rotor is maintained by the thrust bearing that is located on the rotor immediately in front of the turbine bearing. The tapered land thrust bearing consists of a rotating thrust collar on the turbine shaft, which provides the front and back faces of the bearing, and two stationary thrust plates. These plates are supported in a casing, in order, that may be positioned against the rotating faces of the collar.

Gland packing minimizes the clearance between the rotating and stationary elements of the turbine. All the shaft packing are of the metallic labyrinth type. Spring packed, segmented packing rings are fastened in the bore of the high-pressure casing. These rings are machined with alternate high and low teeth that are fitted with minimum clearance into matching groove, cut directly into the turbine rotor. The small clearance and the resistance offered by this series of high and low-teeth construction restricts steam flow to a minimum.

3.2.4 Speed Governor

The function of speed governor is to control speed of turbine when starting up and synchronizing, and to change the load after synchronizing by positioning control valves. The main speed governor also positions both intercept valves through a dashpot linkage connected to its speed relay that acts upon the intercept valve relay operating mechanism. The mechanism is adjusted to operate the intercept valves in a definite relation to the control valves.

3.2.5 Turning gear

The motor driven turning gear with its driving motor is mounted on the turbine bearing cover. The motor drive is transmitted through a silent chain and a reducing gear train to the turbine shaft. The primary function of the turning gear is to rotate the turbine generator shaft slowly and continuously during shutdown periods when rotor temperature changes occur. During shutdowns, the turning gear is used to keep the rotor revolving continuously until the temperature changes has stopped and casing become cool, so that the possibility of distortion is practically eliminated. Apart for this, the turning gear may be used to jack the rotor over small amounts at desired intervals for inspection.

3.3 Stationary system

The turbine cast-steel casing, with its integral steam chest, is particularly adapted for high pressure and high temperature operation. The casing halves are symmetrical, relatively uniform in thickness and have circumferential extraction passage ways. The turbine casing is holed to the front-bearing standard, and four radial keys maintain alignment. This arrangement allows the casing to expand and contract in all directions without disturbing the centerline alignment. The turbine end standard moves forward when the turbine expands.

At the low-pressure end, the casing is bolted to the exhaust casing, which is splited at the horizontal centerline to permit disassembly and inspection. The joint flange surfaces are machined to give full metal-to-metal contact. Steam tightness at these joints is obtained by co-coordinated flange bolt design.

3.4 Oil pumping system

The main oil pump that is centrifugal pump mounted on the turbine shaft supplies oil to the hydraulic mechanism and bearings. Oil discharging from the main pump at about 14 kg/cm^2 is piped to hydraulic header and the individual feed lines branch off from this header, to supply oil to the governing and central mechanism.

The motor driven oil pump is an auxiliary pump of the main pumping system, which supplies operating and lubricating oil. The pump is a centrifugal type, with a single impeller, and is normally driven by vertical induction motor. The pump is primarily used during starting and shutting down of the main turbine, when the turbine is below rated speed and the main pump is ineffective.

4 Generator

The unit three generator is manufactured by Hitachi Ltd., which is a continuous rating, three phase, 60 Hz frequency, 16,000 volts, 3,600 rpm, 2 pole, double star connected and, with B class insulation to generate 150 MW power. The generator is totally enclosed, self-ventilated, forced lubricated, direct hydrogen cooled and the solid cylindrical rotor machine. The generator casing is substantially cylindrical in shape and of welded construction. The end shields at either end of the casing are also of welded construction and support rotor bearings and shaft seals. The all welded construction provides a hydrogen tight enclosure. The generator casing supports the stationary armature. The generator is designed for continuous operation and is constructed to withstand suddenly applied loads or three-phase short circuit. The generator auxiliaries provide control and/or supervision of the hydrogen pressure and purity, shaft seal oil, and temperature of windings, cooling gas, cooling water and lubricating oil.

4.1 Stator frame

The stator frame consists of a gas tight cylindrical casing of welded plate construction, reinforced internally with axial and circumferential plates. The stator frame is supported from the foundation by feet bolted to the sides of the frame. Heavy end shields, which contain the generator rotor bearings, are bolted to the ends of the stator frame. The frame structure also serves as the support and enclosure for the gas coolers.

The armature winding is formed by insulated bars assembled in the stator slots, jointed at the ends to form coils, and connected in the proper phase belts by bus rings. Each phase is split into group coils, one group lying under each pole.

The stator bars are composed of insulated copper conductors arranged in the form of rectangular bars by the transposition method.

4.2 Generator terminal plates

Both the line and neutral terminals are drawn through the terminal plate outside of the generator casing at the collector side. The terminal plate is made from nonmagnetic steel, welded to the bottom of terminal box of the stator. Drains are located in the terminal plates to prevent accumulation of oil or water around the connections.

4.3 High voltage bushings

The line and neutral terminals are drawn out through the terminal boards by means of gas tight high voltage bushings. These bushings consist of one-piece porcelain insulators containing a copper conductor and silver plate. Terminal studs are provided at each end of the bushings for making connections.

4.4 Ventilation of stator

The ventilation of the armature core and windings are accomplished by forcing the cooling gas both inwardly and outwardly through the radial ducts present in the core. The circumferential plates in the frame at the back of the core, together with the outside wrapper plate, form a section that separate the frame into high and low pressure regions through which the cooling gases are forced into or discharged from the stator core. The gas supplied and discharged from these sections is conveyed through pipe or ducts which direct the cooling gas from the fans through the machine and back to the fans through the coolers.

4.5 Generator rotor

The rotor is machined from a single alloy steel forging, with longitudinal slots, machined radially in the body, contain field coils. Additional slots are machined in the teeth and under the coil slots, provide ventilation for the rotor body. The field coils are held in the slots against centrifugal force by wedges, both magnetic and non-magnetic types being used to secure proper flux distribution. These wedges are individually fitted and driven into dovetail openings machined in the rotor slots. The axial fans mounted near the ends of the rotor, draw the gas, and provide ventilation for the generator.

4.6 Field winding and retaining rings

The field winding has rectangular copper bars formed into coils. Several turns in one pair of slots around one pole form a coil. Several coils assembled around each pole to form the winding. The individual turns of the winding are insulated from each other by mica. The coils are insulated within the slot wall in the body portion by molded slot liners made from sheet mica, asbestos cloth, and glasbestos cloth. The end turns are held in place against centrifugal force by heavy retaining rings machined from high strength, heat-treated alloy steel forgings, which are shrunk onto the rotor ends.

4.7 Collector ring

Excitation current is supplied to the field winding through the collector rings, which are connected with the winding through insulated copper bars assembled in the drilled-out center bore of the rotor forging. At one end of the connection bars, terminal rods or studs, assembled in gas-tight bushings into the radial holes on the rotor shaft, that connects the winding with the bars in the other end. Similar studs connect bars with the collector rings. The collector ring consists of a pair of grooved steel rings shrunk onto and insulated from the rotor shaft.

4.8 Brushes and brush holders

The brushes used in alternator are designed to have a small co-efficient of friction and also to have self-lubricating action. Two flexible copper stranded wires, called pigtails, are attached to the brush, and a metallic cap is riveted to its head. A plug attached to the tip of a helical spring is fastened into the hole of this cap; it presses the brush down in its centerline with the 0.67 kg to 0.97 kg pressure towards radial direction with respect to the slip ring.

The brush is housed within the holder case; a number of brush holders are attached together to a copper bus ring concentrically with the collector ring. The bus ring is divided up into two segments, which are clamped together by a clamp fitting. Thus, the bus ring and consequently the brushes are attached in a zigzag position to the sliding surface of the collector ring; this prevents all of the brushes from sliding over the surface of the collector ring along the same path. The cover, which covers the collector rings and the brush holder mechanism, is provided with the door so that these parts can be inspected easily.

4.9 End shields and bearings

The generator elliptical bearings, the shaft sealing, the oil supply and drain piping are supported and enclosed in the end shields. The end shield is divided horizontally in two halves for easy dismantling. The fitting surfaces of these halves, the end shield and the stator frame are finished precisely to ensure the close contact between the surfaces, and has grooves in which sealing compound is filled to insure the gas tightness. The shaft seal prevents the hydrogen leakage through the shaft.

4.10 Shaft seals

A shaft seal of the oil film type maintains the airtight seal at the place where the rotor shaft passes through the end brackets. Seal rings are made from special metal with an inner diameter slightly bigger than the diameter of rotor. These rings are divided into either two or four segments and are fastened in the radial and axial directions by garter springs. Although, the rings are able to move in the radial direction together with the shaft, they are held in place by the pins at the top and bottom of the housing and will not turn around. The sealing oil supplied between the seal casing and the rings runs through the inside of the seal rings in the radial direction, and between the rings and the shaft in the axial direction. Forming an oil film in these areas prevents the gas from leaking outside the alternator along the shaft.

4.11 Hydrogen coolers

The hydrogen cooler is guided with rails and supported on the generator casing. The hydrogen gas is sealed off by means of gaskets between the casing and tube sheets of the cooler. The water feed pipes are connected to the cooler outside the generator and the hydrogen coolers can be removed from every unit of the generator casing, if the water feeding pipes and gas-tight gaskets are removed

4.12 Turbine Generator auxiliary cooling system

The auxiliary cooing system supplies water for generator hydrogen coolers, lubricating oil coolers and boiler feed water pumps. The system is completely closed loop with a head tank and two one hundred percent duty electrical driven circulating pumps. The closed loop is filled with water and make-up is supplied from the unit reserve feed water system. There are three heat exchangers; each of fifty percent capacity dissipates the heat. The cooling water for these heat exchangers is supplied from the unit. **[Refer to flow diagram 4.11]**

4.13 Hydrogen and carbon dioxide systems

Carbon dioxide is used to purge the atmospheric air from the generator casing, and to provide hydrogen atmosphere. Hydrogen gas is used for cooling the generator coils.

5.13.1 Hydrogen gas system

Hydrogen gas is supplied from a three banks, each bank consists of sixteen cylinders. Each bank of sixteen cylinders is connected to a piping manifold and the cylinders discharge the gas simultaneously. Two of the banks of cylinders function as supply and stand-by systems. The supply bank makes up generator hydrogen losses during normal operation of the generator equipment. The stand-by bank is isolated from the system through isolated valves. When the pressure in the supply bank falls to approximately 100 psig the stand-by system is ready for putting into operation. The two banks are then changed over, with the stand-by becoming the supply bank and the depleted bank having its cylinders changed with charged ones and then being put on stand-by. **[Refer to flow diagram 4.12]**

The third bank of sixteen cylinders is intended for generator filling during emergency supply, if the problem arises with the other two banks of cylinders or with the supply system pressure reducing station. Cross over piping and valves have been provided for this purpose. The quantity of hydrogen required is 250 m^3 at operating pressure 207 kPa and the filling rate is approximately $34 m^3/h$. Pressure safety valves on the downstream piping protect the low-pressure piping and equipment from being over pressured. The safety valves are set to operate at 830 kPa. By-pass arrangements are provided to discharge hydrogen to atmosphere. The quantity of hydrogen required to purge the stator frame is 130 m^3 at stand still and 200 m^3 during running. Normally, purging is done when the generator is stopped or on turning gear. If necessary, can be done when the generator is operating. During purging, the generator shaft sealing system must be in operation.

A single bank of six carbon dioxide cylinders discharge gas into common 1" pipe manifold. The pressure in the cylinders at fully charged condition is 5720 kPa. Safety valves and by-pass valves are fitted to ensure protection for the system.

5 Condenser

The ultimate heat sink for a large thermal power station is the atmosphere. There are various options available that use different processes to achieve the most effective heat sink and therefore meet the requirements of the condensing plant and cooling water system. After the steam has surrendered its useful heat to the turbine, it passes to the condenser. Holyrood thermal power units are incorporated with the closed cycle system and have a condensing plant and cooling water system. In order to operate an efficient closed cycle, the condensing plant, cooling water system, and associated pumps must extract the maximum quantity of heat from the exhaust steam of the low-pressure turbine. The primary functions of the condensing plant are:

- To provide the lowest economic heat rejection temperature for the steam cycle.
- To convert the exhaust steam into water and, for re-use the water in the feed water cycle.
- To collect useful residual heat from the drains of the turbine feed heating plant and, other auxiliaries.

The aim of the cooling water system is to maintain a supply-cooling medium to extract necessary heat to meet the condensing plant objectives. In order to fulfill the functional requirements, the system has cooling water pumps, circulating water pumps and air extraction pumps. The entire system is called as heated water system. The cooling water is supplied to the condenser from the sea and the heated water from the condenser outlet is discharged to the sea.

The condenser is designed and supplied by Foster Wheeler Ltd. The condenser shell forms the boundary of the steam envelope. The type of the condenser is the M-single type and has a surface area of 57,670 square feet. The condenser has 7,410 tubes of one inch outside diameter and the effective length is 29 feet. The different subsystems are discussed in the following sections.

5.1 Circulating water system

The circulating water system supplies the cooling water required for the turbine generator condenser, generator hydrogen coolers, turbo-generator lubricating oil coolers, general service water heat exchangers and the mechanical vacuum pump heat exchangers.

The circulating water is seawater, drawn at the pump house. The pump house has two-mixed flow vertical circulating water pumps two dual flow-traveling screens, and the associated screen wash pumps. The seawater passes through the trash racks into the screen fro screening and pumped to the condenser.

The condenser is designed to produce a rated vacuum with two cooling water pumps running at a seawater temperature of 5.6°C. One circulating water pump would be enough during the winter months because of the lower seawater temperature. Both the pumps may be required during the summer and maximum seawater temperature conditions, as one pump will only be sufficient for approximately 65% load under these conditions. However, Ferrous Sulphate dosing is essential for the protection of the condenser tubes from seawater corrosion. In addition, the condenser water boxes are fitted with zinc sacrificial anodes for the further protection of the wind boxes and tube ends from corrosion. The circulating water system flow is initiated by manually starting the circulating water pumps. Screen operation is only affected by either of the following conditions. **[Refer to flow diagram 4.13]**

Pressure differential across the screens

The allowable differential pressure is 10 cm of water across the screens during the operation. When the differential pressure reaches 15.25 cm, a pneumatic rubber bubbler system energizes the screen wash pump motor. Two one hundred percent duty pumps are provided – one normally on stand by. If one pump is unable to attain the required discharge pressure of 525 kPa the other automatically starts. The wash water pumps draw water from the main circulating water pump discharge via strainers and operate only when both circulating water pump and the screen are in operation.

Twenty-four hour timer.

A continuously running adjustable twenty-four hour timer starts screen operation as described above for a period of time and repeats the cycle at set intervals. The initial timing is set for 15 minutes operation after every 4 hours of non-operation. This sequence takes place regardless of the pressure differential as long as there is a minimum pressure of 14 kPa in the screen wash water pump suction line. In either case, the screen continues to run for 1.25 revolutions after the signal to stop is given in order to ensure that all screen panels are cleared of debris.

Motorized butterfly valves are provided for each main circulating water pump discharge. These valves are interlocked with the pump and are fully automatic in operation. The cooling water flows to the main condenser and the auxiliary cooling system circuits. These are two 36" diameter connections, one to each inlet of the divided water box condenser and an 18" diameter branch connection to the unit auxiliary cooling circuits. These valves are fitted on the condenser outlet piping for flow control, balancing purposes and for condenser backwash purposes. Valve controls and position indicators for these valves are located in the plant central room. After passing through the condenser and auxiliary cooling system circuits, the seawater leaves the powerhouse and flows through underground reinforced concrete piping to the sea.

5.2 Amertap tube cleaning system and condenser backwashing

Condenser heat transfer efficiency can be maintained by cleaning the condenser tubes and back washing. The Amertap Washing System is designed for continuous mechanical cleaning of the condenser tubes thus aiding significantly in maintaining heat transfer efficiency. Also, backwashing frequency will be minimized with the use of the cleaning system.

The cleaning system uses specially designed rubber balls that constantly circulate through the system. The constant rubbing action keeps the tube walls clean and free from deposits such as bio fouling, sediment, corrosion products and scaling. The balls are circulated in a closed loop and utilize the pressure drop across the condenser to force the balls through the tubes. The system equipment consists of a ball re-circulating pump, ball collector, ball injection nozzles and strainer sections incorporated in the cooing water discharge legs. The strainer section consists of upper and lower screen sections arranged in 'V' formation for collection of the balls and re-circulate to the pump suction. The strainer sections are fitted with differential pressure switches, which monitor the differential pressure across the upper screen sections. The backwash alarm is initiated at 10 inches of water differential and emergency backwash alarm at 50.5-cm. The complete back washing is recommended to remove sludge etc. from the water boxes

Back washing operation is semi-automatic, the condenser inlet and the outlet valves are motorized, as have the inlet/outlet water backwash valves and the return water box-interconnecting valve. A control unit located in the control room performs the opening and closing of various cooling water valves in sequence automatically. An illuminated mimic panel is provided in the control room to indicate the status of the seven valves involved at any time during the backwash operation. There is a provision for operating the seven motorized valves locally from a control panel located alongside the condenser. When switched to local position, each valve may be operated individually by push buttons on the panel. In addition each valve is fitted with a chain wheel for manual operation if required.

5.3 Condenser air extraction

The condenser air extraction system consists of two 100% duty air extraction pumps, which removes air and, incondensable gases that are present in the steam exhausting from the turbine. The presence of air and incondensable gases must be removed from the condenser because that impairs the vacuum and heat transfer capability of the condenser. The air extraction pumps, located at the west end of the condenser, maintain vacuum in the condenser by drawing off air and incondensable which collect at the center of the tube bundles. The condenser is the divided water box design, two 8-inch piping connections are provided on the condenser shell, one per side and these are connected together with a common pipe, for the air extraction pump section.

[Refer to flow diagram 4.14]

The air extraction pumps perform two functions:

1. Rapid removal of air from the condenser, turbine and other steam spaces during vacuum raising on the turbine generator or "hogging" as it is commonly known. A vacuum of at least 50.8 cm Hg must be obtained before the steam is admitted to the turbine.

2. Maintaining the design vacuum or "holding" under normal operating conditions.

The pumps are liquid ring type manufactured by Siemens A.G. Although a single stage impeller is used. the pumps perform both hogging and holding operations by virtue of a specially design discharge port. The water forming the liquid ring within the pump is cooled in a heat exchanger by seawater from the circulating water system. Make-up water for the liquid ring is supplied from a tank integral with the air exhauster package. The hogging capacity time required for evacuating, 623m3 of gases from atmospheric to 25.4 cm Hg absolute is 15 minutes. The holding capacity 0.44m^3/minute at 2.54 cm Hg. absolute, with 18.3°C cooling water and, 0.64m^3/minute, with 1.7°C cooling water. A vacuum breaker valve is installed in the condenser air extraction line to control the speed of the turbine, when it is off-loaded. The valve is motor operated, and can be opened from the control desk. An air filter is installed on the upstream side of the valve to prevent the ingress of dust when the valve is opened.

5.4 Turbine-Generator auxiliaries and boiler feed pump cooling system

The auxiliary cooling system supplies coolant for the turbine-generator hydrogen coolers, lubricating oil coolers, and feed water pumps. The system is completely closed loop with a head tank and two 100% duty, electrically driven circulating pumps. The pump circulates coolant through auxiliary heat exchangers on the shell side, then around two separate piping loops, one feeding the generator hydrogen coolers and returning to the pump suction, the other loop feeding the boiler feed pumps and the turbine generator lubricating oil coolers then returning to the pump suction. It is completely filled with treated condensate and the make-up from the unit reserve feed water system. The heat is dissipated from the system by three heat exchangers, each of 50%

capacity. These are supplied with cooling water from the unit main circulating system. They are of the horizontal straight tube type fitted with quick opening doors for cleaning purposes.

5.5 General service cooling water system

The general service water system is designed to conserve raw water. The system provides cooling water for the following equipment: air compressors, control room air conditioners, excitation room air conditioner, condensation extraction pump motors, high pressure heater drain pump seals, forced draft fan bearing cooing, main air pre heaters, water and steam sample cooling station, and local grab sample station.

The service water is chemically treated clarified water and is circulated through the system by two 100% duty horizontal centrifugal pumps of 12.62 liters/second nominal capacity.. The storage tank, acts as a head tank to the service water system and is connected to the general service water pump suction. In the event that either pumps or both heat exchangers are out of service, the closed system can revert to the open system. Make-up water to the service water tank is supplied from the water treatment plant.

6 Feed water system

The feed heating system associated with a turbine provides the means by which the steam condensed in the main condenser is fed to the boiler. It is also used to heat the feed water with the use of series of heat exchangers as demanded by the cycle design.

6.1 Functions of feed water system

1. Provides the required amount of feed water to the boiler at a temperature dictated by the cycle design.
2. Maintains stable suction regime for the boiler feed pumps.
3. Contains a buffer store for the water to allow for a short-term mismatch between the boiler demand and the available feed water.
4. In the longer term it keeps the water content constant.
5. Supplies water to the boiler with an acceptable oxygen content.
6. Automatically cut-off the supply of contaminated feed water to the de-aerator, and to the boiler, in the event of, condenser leakage or the chemicals from the polishing plant.
7. The feed water system contains lot of stored energy; it protects turbine-generator from over speed, during the turbine trip or sudden reduction of speed.

The system consists of low pressure feed water system; high pressure feed water system and reserve feed water system.

6.2 Low pressure feed water system

The low pressure feed system is defined as the heaters and the equipment between the outlets of the condenser hot well and the condensate inlet to the de-aerator system. As the name implies, the system conveys and progressively heats low-pressure condensate from the condenser hot well to the de-aerator storage tank. In addition the condensate is utilized in condenser flash box, LP turbine exhaust hood, gland sealing water for the boiler feed pumps and as a water supply to the phosphate and hydrazine chemical injection units. **[Refer to flow diagram 4.15]**

The system consists of two one hundred percent capacity electrically driven condensate extraction pumps, a gland steam condenser, two low-pressure feed water heaters and a tray-type de-aerating heater. The system incorporates several features designed to maintain constant quantities of condensate in the cycle. The pumps are vertical canister type, draw the condensate from the condenser hot well, pumping it progressively, through the gland seal condenser, #1 and #2 low pressure heaters, and finally into the de-aerator.

The gland steam condenser and low-pressure heaters have stainless steel tubes for corrosion protection. The de-aerator is equipped with heavy-duty stainless steel trays for improved strength and reliability. The de-aerator storage tank contains approximately 81,648 kg of condensate at normal operating level or the enough condensate to supply the boiler feed pumps for approximately ten minutes at full load. A pneumatic control valve LV-3528 located between the gland seal condenser and #1 low-pressure heater controls condensate admission to the de-aerator by maintaining a constant level in the storage tank. An electronic, two-element controller LK-3528 operates the valve, which receives input signals from the de-aerator storage tank level and feed water flow

The operator interface for the controller is located on the control room auxiliary instrument panel. Separate level switches are provided on the de-aerator storage tank for high and low level alarm annunciation. Additional storage tank level switches are provided to shut down the boiler feed pumps and condensate extraction pumps on extremely low and high level and to trip the bled steam trip valves. This variation in level is used to control admission of make-up to, or rejection of surplus condensate from the system. Increasing level in the hot well opens the reserve feed water system surplus control valve LV-3501B and allows condensate to be rejected from the low pressure feed water system from a point downstream of the gland steam condenser to the high level reserve feed water storage tank. Conversely, a falling level in the hot well opens the reserve feed water system make-up control valve LV-3501A which admits water to the condenser from the high level feed water storage tank until the hot well level is restored to a normal.

The control output of the hot well level control system is split between these two control valves with a dead band at mid range to ensure that only one valve is open at time. A level switch fitted on the high level reserve feed water storage tank will trip the make-up motorized isolating valve to the closed position in the event of low level in high reserve feed water tank to prevent loss of condenser vacuum. The high and low level switches fitted to the condenser hot well annunciate abnormally high and low levels. The low level switch will also stop the condensate extraction pump.

The control valve FV-3512 is opened to re-circulate the water back to the condenser during the flows to the de-aerator below 28 kg/s that, prevents damage to the condenser extraction pump. The water levels in the condenser hot well and the de-aerator storage tank are indicated on the unit control board in the control room and are inputs to the data logger. The dropping of level in the high level reserve feed water tank actuates a control valve which permits water to flow from the de-mineralized water storage tanks in the water treatment plant to the condenser hot well. This raises the level in the condenser hot well and, as explained above, rising hot well level opens the system surplus control valve reserve feed water storage tank thus restoring the level in this tank. Spray water from the system is supplied to the LP turbine exhaust hoods and the condenser flash box.

6.3 High pressure feed water system

The feed water supply for the steam generator originates at the de-aerator; two electrically driven feed pumps each of fifty percent capacity pumps the water. These pumps draw feed water directly from the de-aerator storage tank and each is capable of supplying up to 90 MW load and for excess load the pumps are operated in parallel. The pumps are double case horizontal construction; rated at 75 L/s and coupled to a 3550-rpm, 2350 horsepower and, three-phase electric induction motor. The pumps discharges water at high pressure through the high-pressure heaters and then into the economizer inlet of the generating unit. The system incorporates a suction valve, a suction strainer and suction flow meters on each boiler feed pump to indicate flow and alert control room operator on pump flow conditions. It also contains combination of check and re-circulation valve, main feed water flow meter, spray water flow meters, feed water control valves, spray water control valves and Nos. 4, 5 and 6 high pressure feed water heaters, piping and miscellaneous instruments. In addition, the water is supplied to the super heater attemperator spray nozzle, the emergency reheat attemperator spray nozzle, the auxiliary steam de-super heater, the start-up de-super heater and for feed pump warming. A relief valve is fitted between the pump and its associated suction valve to protect the low-pressure parts during opening of warming line with the pump suction valve closed. The pump suction valve is fitted with a limit switch, which prevents the pump from being started unless the valve is fully open. **[Refer to flow diagram 4.16]**

The spray water from the boiler feed pump discharge is supplied to super heater and re-heater attemperators. The water is required to maintain the super heater steam temperature at 538° C above approximately 70% load. . On demand for reheat spray water, the controlling valve opens and a limit switch mounted on it actuates block valve, which moves to the fully open position. A manually operated drain valve installed between the two control valves is intended for periodically testing for block valve leakage. The same source of spray water is used to supply the auxiliary steam de-superheating station and start-up de-superheating station.

Two control valves are provided to regulate the supply of feed water to the steam generator economizer. The 3" size valve operates during start-up and is in operation up to approximately 25% load. The 10" control valve takes over above twenty percent load and that will be in normal operation. A control system is available for automatic sequencing of opening and closing of these valves. The control system is of the three-element type-utilizing signal from boiler drum level. The feed water flow nozzle is located on the 10" feed water supply header upstream of the control valves manifold.

To permit bypassing of feed water heaters motorized isolating and bypass valves have been installed. Individual bypassing has been provided for heater # 6 so, that it can be taken out of operation to allow increased operating capacity. The bypass system will also operate automatically if an abnormally high level of condensate is detected in the shell of the heater. The heaters 4 and 5 are coupled and are bypassed together. These heaters will also be bypassed if high water level is detected.

6.4 Reserve feed water system

The reserve feed water system is an essential part of the boiler feed water system. It provides storage for large quantities of condensate for normal make up and during emergency requirements. It also provides adequate storage to meet boiler start up requirements as large quantity of steam is discharged to atmosphere from the super heater, starting vents and from other drains. It consists of a high level and a low-level storage tank, together with the transfer pump, interconnecting pipe work, valve controls and instrumentation. The system supplies make-up feed water to the condenser or receives surplus condensate from the low pressure feed water system. The system also supplies water for chemical feed units, gland sealing system, make-up water to the turbine generator auxiliary cooling system head tank and sealing water for the main condenser air extraction pumps. **[Refer to flow diagram 4.17]**

6.5 Chemical injection system

Boiler feed water is chemically controlled to prevent corrosion of boiler evaporator surfaces, super heaters, re-heaters and turbines. A solution of hydrazine is fed to mix with the condensate extraction pumps. This compound has the ability to absorb oxygen with an end product of nitrogen and water. This also prevents the increase of boiler water solids and raises the pH as well as scavenging oxygen and protects the entire wet portion of the cycle against corrosion and iron pick up. **[Refer to flow diagram 4.19]**

Morpholine is also used to control pH. This amine is added to the condensate at the discharge of the condensate extraction pumps to maintain the proper pH level. When Morpholine reaches the boiler it is vaporized with the water and passes along with the steam. It condenses with the steam and is therefore effective in maintaining a high pH in all parts of the system.

The chemical supply system has solution tanks and two one hundred percent capacity positive displacement-metering pumps (One pump is standby) driven at constant speed by electric motors. The upstream and downstream of manual isolating valves on the standby pump of each system are kept closed until the pump is required to run. Adjusting the calibrated eccentric on the speed reducer to alter the length of stroke manually controls the quantity of chemical solution discharged by the pumps. The pump operating capacity is 0.247 L/s. and same for the both pumps. The dilution water is supplied from the high level reserve feed water storage tank. A safety valve and a pressure gauge are fitted to the discharge of each metering pump.

6.6 Boiler feed pumps Gland sealing water system

The pumps are fitted with throttle bushings, where the shaft comes through the outer barrel ends. A seal is required to prevent the escape of hot condensate and to minimize the possibility of wear of the shaft in the bushings. The cool condensate serves as a seal. The clearance between the shaft and throttle bushing is 0.014" to 0.015" (radial) and there is neither conventional packing nor a mechanical seal. The cooling sealing water is fed into the throttle bushing about two-thirds along its length, nearest to the pump end, and at a pressure of 15 psi, above the pump suction pressure.

Under normal operating conditions the water supply for the boiler feed pump gland seals is taken from the L.P feed water system at the discharge of the condensate extraction pumps, upstream of the gland seal condenser. The pressure at the inlet to the system is 1725 KPa and if the pressure at the inlet fall to 1035 KPa, pressure switch will cause the gland seal water injection pump to automatically start and supply water to the system. This pump takes its suction from the reserve feed water system. For the correct operation of the gland seals the supply water must be maintained at a constant pressure of 15 psi above the suction pressure of the pump. The water when it drains from the stuffing boxes is collected in the gland seal drain tank from where it is pumped to the surface condenser. Level controls are fitted to the tank to maintain a constant water level and to alarm on abnormally high and low water levels.

6.7 Feed water heaters

The thermal efficiency of the steam plant cycle is increased by adding feed water heaters and, acts as a heat exchanger that will raise the temperature of the incoming feed water to a specified outlet temperature, by drawing a predetermined amount of steam from the turbine cycle. There are three groups of heat exchangers used in the feed system to fulfill this function:

- High pressure feed water heaters
- Low pressure feed water heaters
- De – aerator heaters

The feed heaters 4, 5 and 6 are located in the high pressure feed water system and the heaters 1, and 2 are located in the low pressure feed water system. The low-pressure heaters 1 and 2 are closed, U-tube, two-pass type with carbon steel shells and have stainless tubes.

High and Low pressure feed water heaters

The high-pressure heaters are closed, U – tube, two pass, horizontal type with carbon steel shell and tubes. The heaters are manufactured by Foster Wheeler Limited, Canada and have three zones to heat the feed water. The condensing zone heats the feed water by removing the latent heat. A system of baffles is provided for an even distribution of the steam throughout the length of heater. The extraction steam enters through this zone from the steam inlet nozzle near the thermal centerline and flows in both directions, directed by evenly spaced baffles. The accumulation of non-condensable gases reduces efficiency by decreasing the effective surface and cause corrosion. The vent connections, located at the end of the shell provide the means to remove non-condensable gases. The sub-cooling zone reduces the temperature of the drains, leaving the condensing zone, below the saturation temperature by transferring heat to the entering feed water. The sub-cooling zone is located on the feed water inlet pass and is enclosed by wrapper plates. This reduction in temperature reduces the tendency of the drains to flash within the piping while being transferred to the next lower stage.

The high-pressure heater, has an integral de-superheating zone, and the enveloping wrapper plate encloses the tubes for the second or return tube pass for a given tube length. This is an independent section or sub-assembly constructed with a twin-enveloping baffle of all welding construction. The de-superheated steam is circulated and spaced to meet the heat transfer requirements with a minimum loss of pressure. A steel impingement plate is provided beneath the steam inlet nozzle.

De-aerator feed heater

The water from the condenser, heated by the low pressure feed heaters, is supplied to the de-aerator. The water is further heated and de-aerated; fed to the boilers by the boiler feed pump, via the HP feed train. The de-aerators are designed to provide feed water with not more than 5 micrograms per kilogram of oxygen.

The de-aeration is achieved by the application of Henry's Law, which states that the quantity of gas dissolved in a given quantity of solution is proportional to the partial pressure of that gas over the solution. When this law is applied to the removal of oxygen from feed water, where the atmosphere above and around the condensate contains no oxygen, then the dissolved oxygen will escape to the atmosphere in attempt to achieve equilibrium.

The de-aerating heads and tanks are cylindrical pressure vessels, with dished ends constructed of mild steel. The spray nozzles and trays are made of stainless steel to prevent corrosion. The spray water distribution system and tray support structure, are made of mild steel and the perforated stainless steel trays are supported and held by this structure. The water flows through the head where it is heated and de-aerated before it drains to the storage tank. The design uses spray nozzles to produce a fine film/spray to maximize the surface area of the water available to the steam for heat transfer and to minimize the distance that the oxygen has to travel to be released. The residual oxygen is released while the water is further heated as it passes over a series of perforated trays, which causes the condensate to fall as continues 'rainfall' from tray to tray.

6.8 Turbine extraction steam system

The bled steam is extracted from the turbine at different expansion stages. The steam from the HP cylinder is utilized for the 6 heater, the extraction point being on the cold reheat line. The heaters 3, 4 and 5 are fed from the 8^{th}, 10^{th}, and 12^{th} stage extraction points, which are on the turbine IP cylinder. The steam is bled to 1 and 2 heaters from the extraction points on the 14^{th} and 16^{th} stages of the double flow low-pressure section of the turbine. The bled steam to the heaters is carried in two pipes. An isolating valve is fitted to the bled steam piping for each heater. These valves are manually operated except for the one on the # 6 heater bled steam line. A power assisted reverse flow check valves are installed in the bled steam piping, to each heater, to prevent steam flow reversal to the turbine in the case of emergency trip. A second check valve is provided in the bled steam piping to the de-aerator and is installed close to the de-aerating heater. Two check valves in series are required because of the large quantity of entrained energy contained in the de-aerator storage tank. **[Refer to flow diagram 4.19]**

A three-way solenoid valve is installed in the air supply line to each bled steam check valve. A liquid level switch actuates solenoid to close the check valve and stop the supply of bled steam when abnormally high condensate level is detected in the shell of the heater. The downstream sides of each bled steam check valve is fitted with an automatic drain trap. The traps discharge to the condenser flash tank and are installed to prevent the possibility of condensate draining back through the bled steam lines to the turbine. In addition, automatic drain traps are fitted at the low points in the bled steam piping upstream of the check valves. The temperature, flow and pressure conditions of bled steam to each heater are transmitted to control room.

6.9 Feed water heater drains system

The bled steam gives up heat to the feed water by condensing in the heaters. The condensate levels within the closed heaters are controlled by regulating the quantity of condensate discharged to the drainage system. The difference in pressure between succeeding heaters permits cascading the drains from one heater to the next lowest. The high-pressure heaters 6,5 and 4, when in normal operation, drain from 6 to 5 to 4 and from 4 to the direct contact de-aerating heater. The low-pressure heaters 2 and 1, when in normal operation, drain from 2 to 1 and from 1 are pumped forward into the low pressure feed water system. In a heater 6, a higher level than normal will cause the drains to be diverted directly to the de-aerator. If the heater level continues to rise to a present high limit, the bled steam supply will be shut off and the heater will be automatically by-passed on the high pressure feed waterside. **[Refer to flow diagram 4.20]**

On raising the level in heater 5, the drains cascading from heater 6 will be shut off. On further increase in level to a preset high limit, the bled steam check valves for heaters 5 and 4 will close and both heaters will be by-passed on the high pressure feed waterside. On the condensate reaching a high level in heater 4, the drains cascading from heater 6 into heater 5 will be shut-off and the drains from the heater No.4 will be diverted to the condenser. The continued increase to the preset high-level limit will cause the bled steam check valves to close and heaters 4 and 5 to be by-passed on the high pressure feed waterside.

The low-pressure heater 2 cascades its drains to low-pressure heater 1 when operating at the normal water level. The drains will be diverted to the condenser if the level rises to a preset level. The continued level increase to a maximum setting will cause the bled steam check valve to close. Under normal level conditions and with unit load above thirty percent, the drains from low-pressure heater 1 are discharged into the low pressure feed water system using one of the two one hundred percent capacities drain pumps. To provide more stable conditions for pump operation, a drain tank is placed between low-pressure heater 1 and the pump. The condensate in the tank is at the same level as the condensate in the heater and the two vessels are maintained at the same pressure, both being connected to the same bled steam supply. If the water level should not be maintained in the heater as it rises to a preset level, the drains cascading from low-pressure heater 2 will be shut off and the dump valve on the drain by-pass to the condenser will be open. Further level increase in low-pressure heater 1 to a preset high limit will close the bled steam check valves. Controls are provided for the low-pressure heater drain pumps so that the stand-by pump will automatically start if the running pump were unable to maintain pressure. The running pump will trip if the level in the drain tank falls to a minimum low setting.

6.10 Feed water heaters vent system

The high and low pressure closed type feed water heaters are fitted with both start-up air purge vents and continues air vents. The purge vents on the high-pressure heaters discharge into a common header, which is connected to the surface condenser. A globe valve on the header is motorized and, prior to steam admission, the three heaters are normally purged of air simultaneously. Individual motorized air purge vent valves and piping are provided on the low-pressure heaters. These vent pipes are also taken to the condenser.

To prevent entrapped air from accumulating between the baffles in the heaters, continuous vents are required on each of the high-pressure heaters. The vent consists of a central tube drilled with holes in different baffle areas. On the discharge piping a flow restricting orifice is installed. A normally closed, manually operated by-pass around the orifice plate permits a higher rate of venting during testing the heater operation. A common vent header carries the continuous vents from H.P heaters 6,5 and 4 to the condenser.

Connections on the sides of the low-pressure heaters, along the length of the heaters, are provided for continuous venting. These vents are fitted with flow restricting orifice plates and discharge via a common header to the condenser. A by-pass is fitted around each restricting orifice, the normally closed valve being opened when testing heater operation.

The de-aerating heater vent piping allows the vents to be either taken to the condenser or discharged to atmosphere. A safety valve is fitted to the shell of each heater. The high-pressure heaters and the de-aerating heater safety relief valves vent into a common vent line to the outside of the boiler house and the condensate from the vents drains to waste. The vents on the discharge of the low pressure feed water heater safety valves discharge to the floor drainage system.

7 Water treatment plant

The de-mineralized water plant is an integral part of power generation at the Holyrood generating station. The water is drawn from Quarry Brook, refined in the water treatment plant and enters a continuous water/steam cycle as make-up water. Each time it passes through this cycle, it is purified in the condensate polishers. The condensate polisher is located beside the condenser, under the turbine.

There are three main types of impurities in water, ionic and dissolved, nonionic and un-dissolved and gaseous. These impurities found in water can have various detrimental effects, when the water is used in a manufacturing process. The first effect is a scale formation in boiler and other heat exchanger equipments. This is a result of hard water and acts as an insulating material, preventing heat transfer and causes boiler tube failure through overheating of the tube metal walls. The second area of concern is impurities carried over into the steam. The silica volatizes under pressure and can deposit on the blades of steam turbines, decreasing their efficiency rapidly. The third major area of concern is the corrosion of metal surfaces in contact with water and steam, which is the major maintenance expense in the power industry. These adverse effects are primarily caused by ionic impurities in the feed water and are minimized by de-mineralizing the water. The demineralization is accomplished through an ion exchange process.

The water treatment process consists of four steps

a. A pretreatment stage to enhance clarification,

b. A clarification stage involving settling and filtration,

c. A demineralization stage, utilizing a strong acid and cation exchanger, a strong base anion exchanger, and mixed bed exchanger,

d. A polishing process on the steam condensate.

7.1 Raw water system

The fresh water from the dam reaches the raw water sump. The water is pumped to the clarifier through a control valve from the raw water sump. The suspended un-dissolved matter from the water is removed through water clarification that is accomplished by a process of coagulation, settling and filtration. The coarse particles of suspended matter settle down, but some suspended impurities such as turbidity and color, are finally divided or even colloidal, and do not settle readily. Coagulation, induced by adding chemicals to the water, agglomerates the finely divided, suspended solids into masses that settle more readily, leaving clarified water. The water treatment plant uses a gravier re-activator for clarification of the raw water. Alum is used as a coagulant, lime for pH control; a coagulant aid is used to improve performance. The alum and lime are fed in powder form using Wallace and Tiernan dry feeders and the coagulant aid is mixed in a tank and fed as a liquid. The plant chemists determine the necessary dosages of these three chemicals and feed rate is adjusted. The inlet flow to the clarifier is measured with flow totalizer and the rate of chemicals addition is set as a proportion of raw water flow. The inlet flow meter is fitted with a mechanism, which initiates the operation of the chemical feeders each time, so that, fixed quantity of water has been passed, independent of the rate of flow.

The graver re-activator is a solid-contact type treatment unit in which, large quantities of re-circulation precipitates are thoroughly mixed and kept in intimate contact with incoming raw water for an extended period of time in the center cone of the re-activator. The ultimate contact between the water, treating chemicals, and previously formed precipitates causes the chemical reactions to proceed at a rapid rate with a minimum of treating chemicals.

The draft tube, and impeller, which is driven by the variable speed drive, is essentially a low lift vertical pump. Re-circulating sludge is drawn into the lower draft tube around the bottom of the draft tube extension and flows upward through the draft tube and discharges near the top of the cone. The raw water and treatment chemicals are introduced into this re-circulating sludge stream where they are thoroughly mixed. After leaving the upper draft tube, the water and re-circulating sludge flow downward beneath the cone, where one portion of stream will flow back to the lower draft tube for continued re-circulation. The sludge scraper continuously moves precipitates, which settle to the floor of the re-activator, to the central sump where they are concentrated and periodically blown off to waste. The clarified water in the collector flows by gravity to three dual compartment mono valve filters to remove those suspended materials that have not settled down.

7.2 Mono valve filters

The mono valve filters are gravity fed sand filters. There are three dual compartment filters running in parallel. They contain their own backwash water internally, the backwash is initiated automatically on high pressure, and backwashing is implemented by operating a valve. During a service run, the incoming water percolates through the filter bed to the false bottom, where the Partilok strainers collect it. The filtered water flows to the backwash compartment from the under drain compartment and out to service. The water level in the backwash storage compartment remains fixed, while the backpressure increases gradually above the filter bed. This continues until the backpressure reaches the predetermined point, usually above .5 feet of water, at that point a pressure switch will initiate a backwash.

When the pressure switch is activated, the PLC activates the control valve for the filter compartment with the high backpressure. This causes the water in the back wash compartment to flow up through the filter bed, expanding and backwashing the sand bed, and proceeding down the tail pipe and into the sump. The water filtering through the other compartment is also used as backwash water

After filtration, the water flows from the mono valve filters to the clearwell. Modulating the inlet flow to the clarifier as detailed in previous sections controls the level in the clearwell. Water is drawn off the clearwell by two clarified water pumps, pumped to clarified water storage tank in the top of the boiler house, and pumped direct to the inlet of the de-mineralizer plant. The clarified water storage tank provides cooling water flow to the general cooling system, and also pressurizes and provides large volume storage backup for the fire protection system.

7.3 De-mineralizers

Demineralization is a process of removing the mineral salts from water by ion exchange. There are two basic ion exchange reactions in demineralization. The first reaction is removal of metallic cations on a strong acid cation exchanger. To complete the ion exchange, the second stage removes the anions in a basic anion exchanger. A mixed bed de-mineralizer is used as the last step to further purify the water by removing any ions that are leaked by the first two stages. A mixed bed de-minearlizer has both types of ion exchange resins in the same vessel.

7.4 Condensate polishers

The condensate polishers are utilized to remove trace impurities from the feed water. This is important during plant start-up for which they are used to remove crud from the system. The secondary use is to remove salt when a condenser leak occurs to allow chemical adjustment and/or orderly shutdown. Polishing is comprised of two processes: filtration and ion exchange. A mixed bed de-minearlizer can perform both the ion exchange and filtration necessary to provide pure feed water.

8 Instrument and service air system

Compressed air is required to operate the power plant instruments, valves and to seal the furnace to prevent gases out from the furnace. It is divided into three systems as described below.

8.1 Instrument air system

The instrument air system supply dry and oil free air for the power plant instrument requirements. The air is supplied from the service air system by two Atlas Copco compressors. The air flows through an isolating valve and check valve to the pre-filter and the air dryer after discharged from the compressor. After drying, the air passes through a second filter before entering the power plant instrument air receivers The air is piped to the instrument and control facilities throughout the plant from the receivers. The receivers are connected in parallel with valve facilities for isolation. **[Refer to flow diagram 4.21]**

A pressure control valve is installed on a main branch discharge header of the service air compressors. If the pressure in the instrument air system drops to 580 kPa this valve will open and by-pass the instrument air dryer to supply the air for emergency requirement.

8.2 Service air system

. The compressed air from both the compressors, discharged to the air receivers through check valve and isolating valves. The service air receivers are connected in parallel with valve facilities for isolation. The air is supplied for the atomizing and aspirating air systems, the gas temperature probe and for driving the air motors on the air pre-heaters.

8.3 Boiler aspirating, sealing and scanner air system

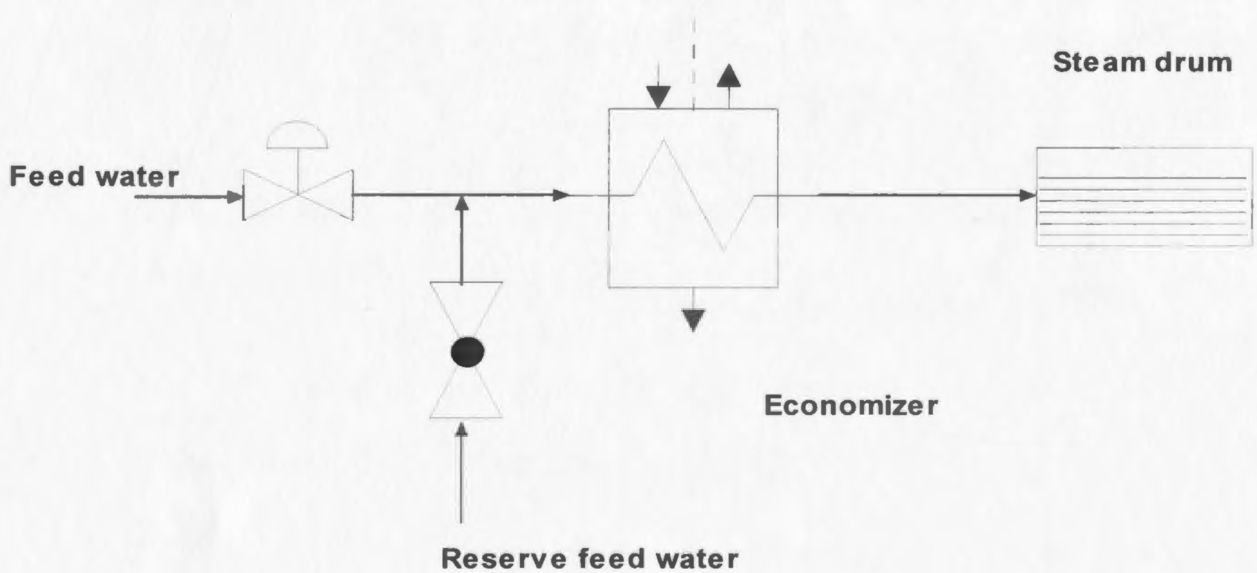
The aspirating air discharges into the wall box opening to create a barrier, which prevents the escape of hot furnace gases from the furnace. The air must be put on when the steam generator is in operation and it is required to open an observation door or port to remove a piece of equipment for servicing.

The sealing air is used to prevent gas leakage, from the places, where the equipments protrude from the steam generator. In addition, sealing air is used for sealing leaks, to prevent plugging of aspirating jets, to provide cooling and to keep fly ash out of the ports. The air supply is taken from the discharge of the forced draft fans. The interconnecting piping is furnished with the steam generator. The aspirating air distribution piping is also furnished with the steam generator and the air is supplied from the service air system.

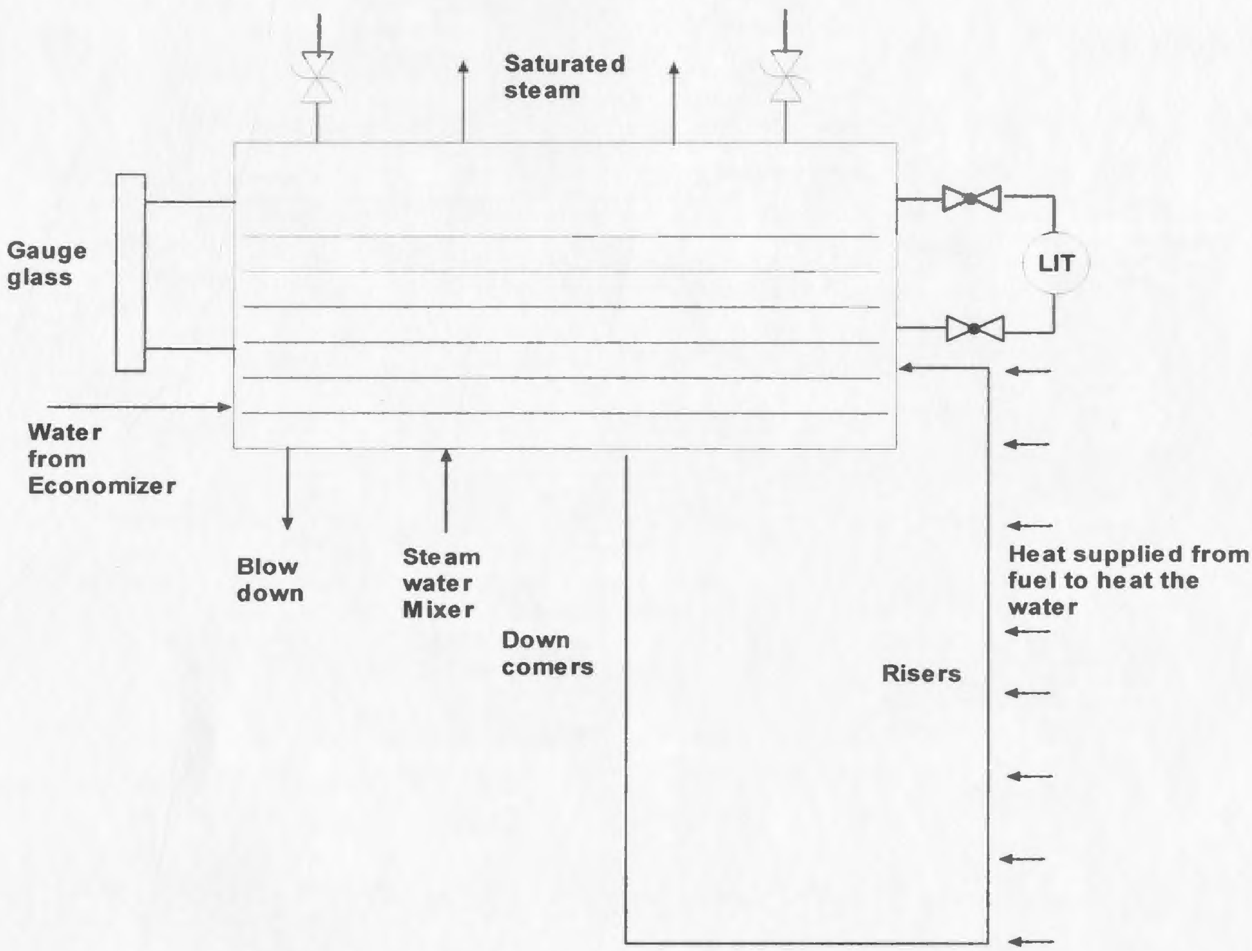
Each burner has 3" observation window, carbon arc igniter, which are required sealing and aspirating air. Oil burner and scanner assembly, are required aspirating air. Aspirating air is also provided to the scanner packing gland assembly and is required when isolating tube is removed for service. The scanner requires a continuous supply of purge air from the cooling air blowers when the steam generator in operation. The temperature of scanner will rise and causes the scanner output to fall if the purge air supply is not available.

Appendix B – Flow diagrams

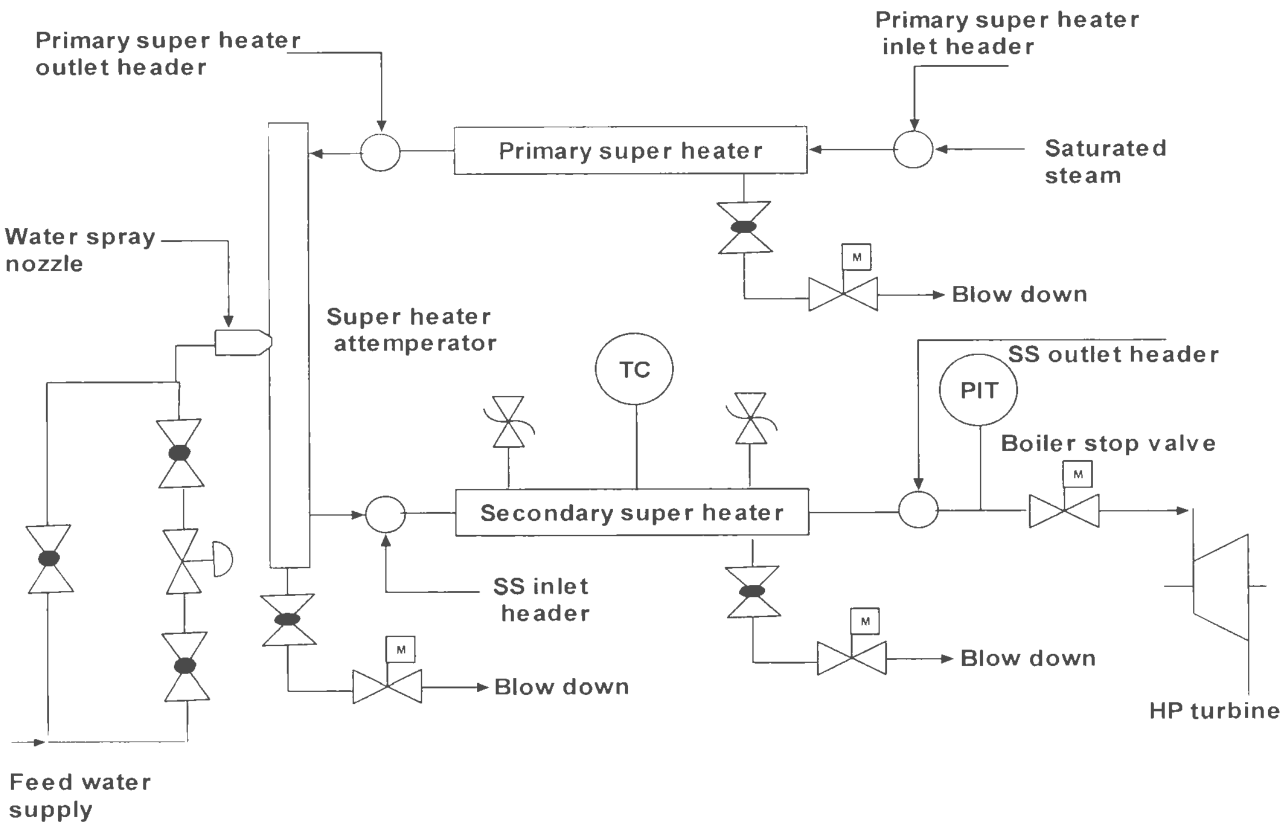
4.2 Economizer



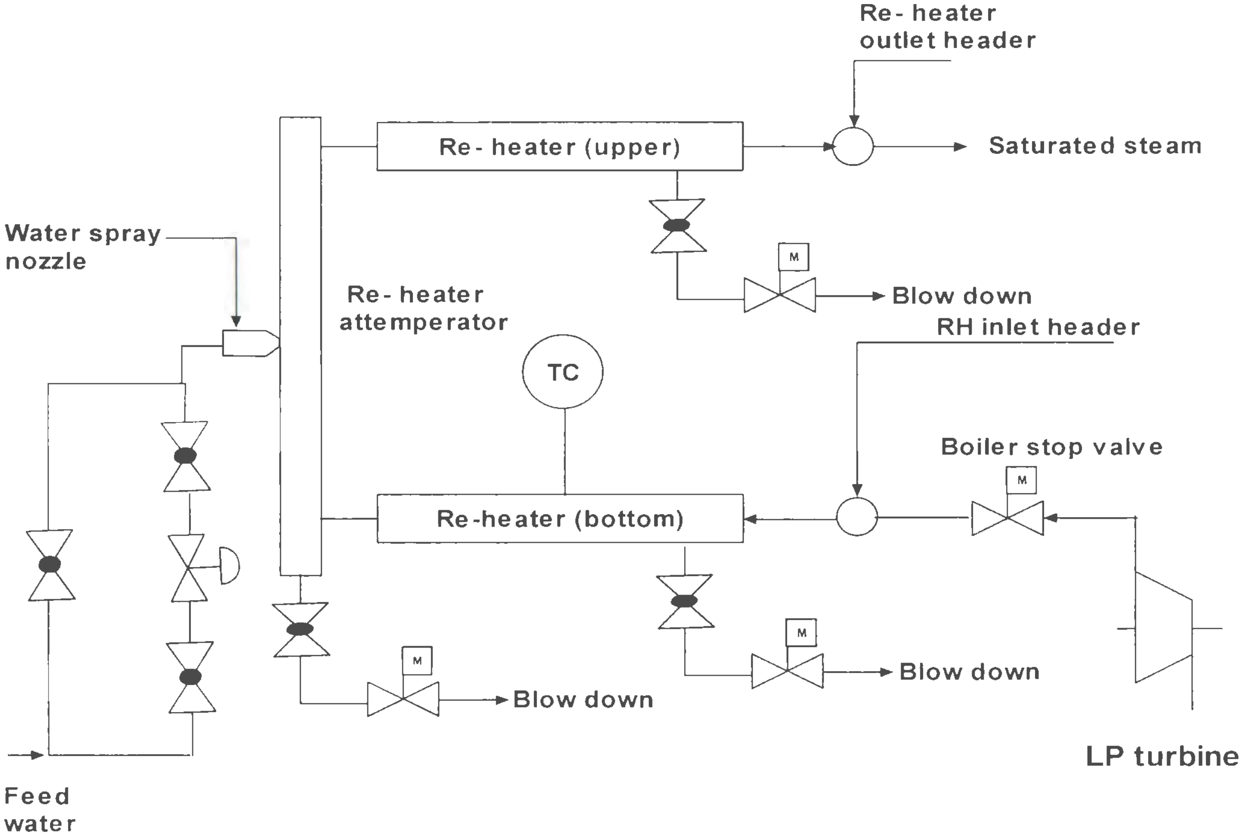
4.3 Steam drum



4.4 Super heater

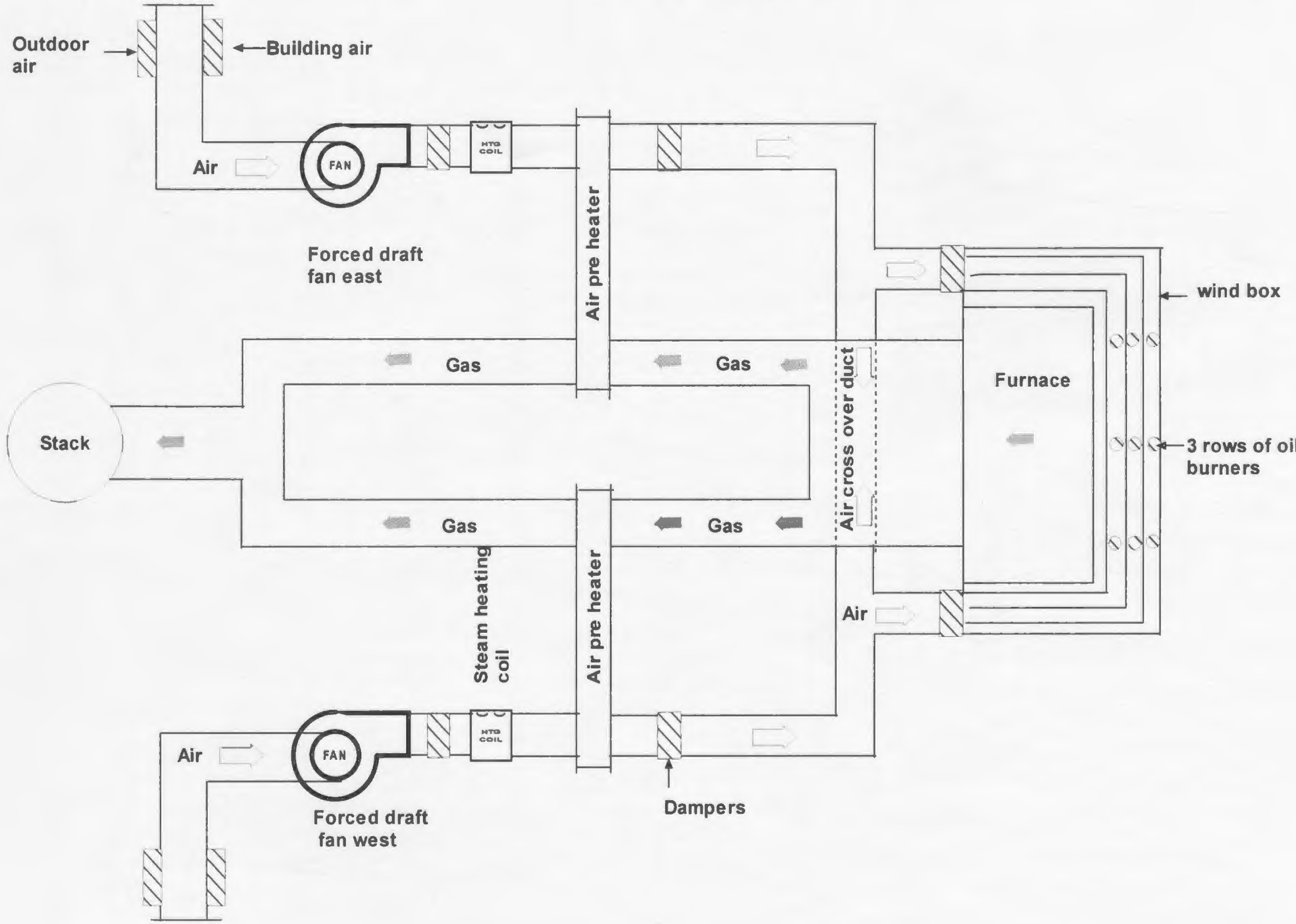


4.5 Re-heater

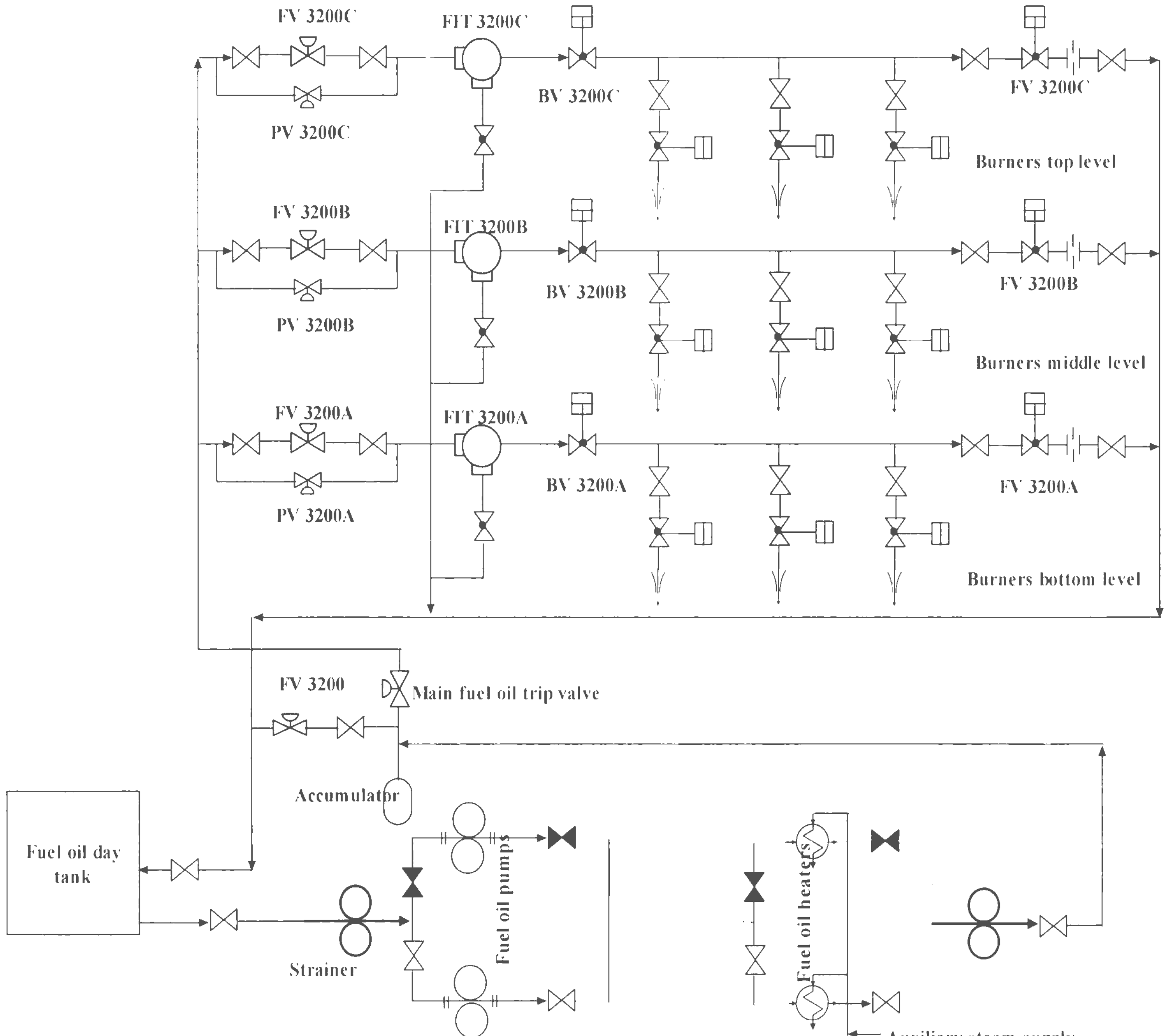


Re- heater
outlet header
Re- heater (upper)
Saturated steam
Water spray
nozzle
M
Blow down
Re- heater
attemperator
RH inlet header
TC
Boiler stop valve
M
Re-heater (bottom)
M
M
Blow down
Blow down
LP turbine
Feed
water

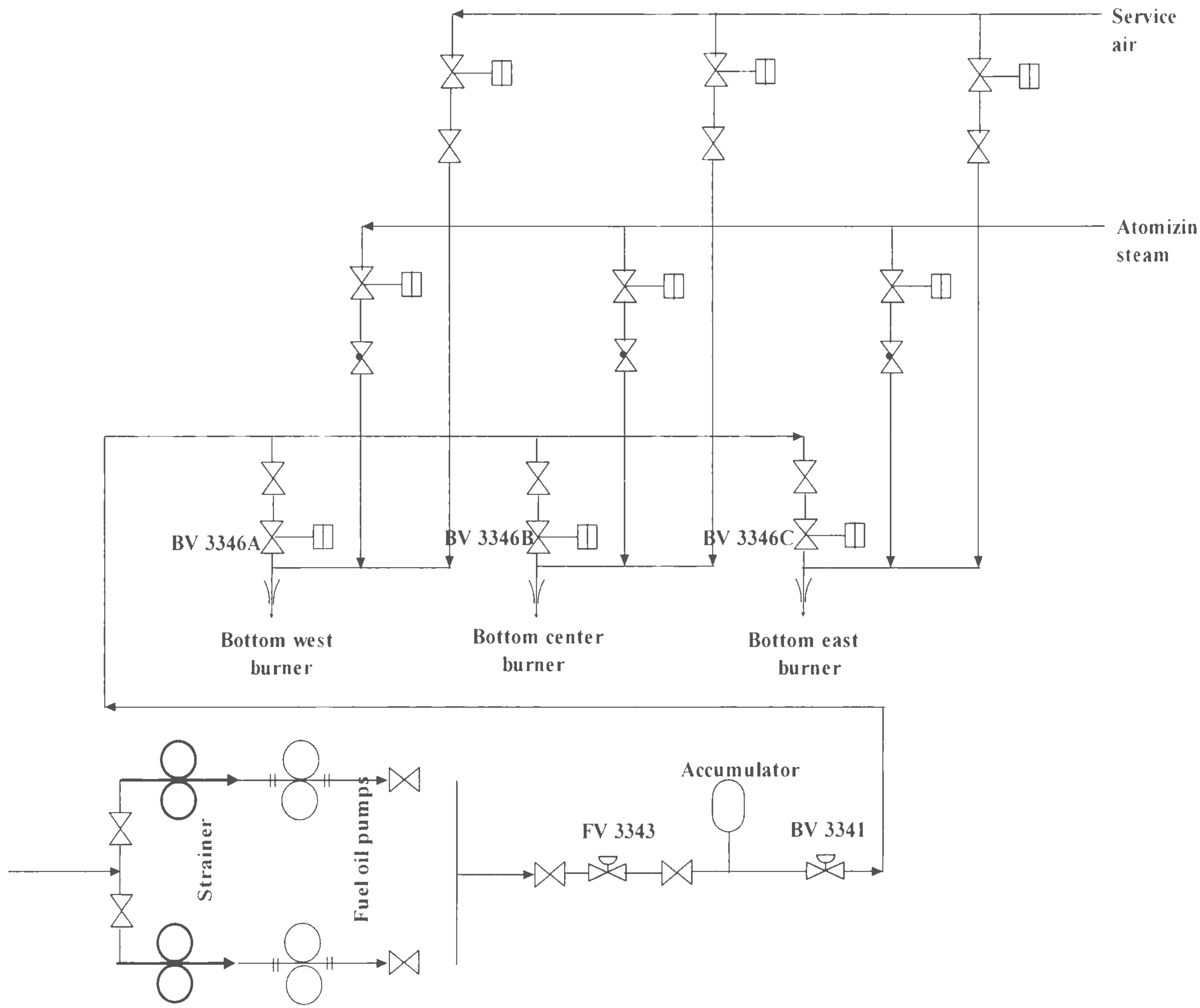
4.6 Air and flue gas system



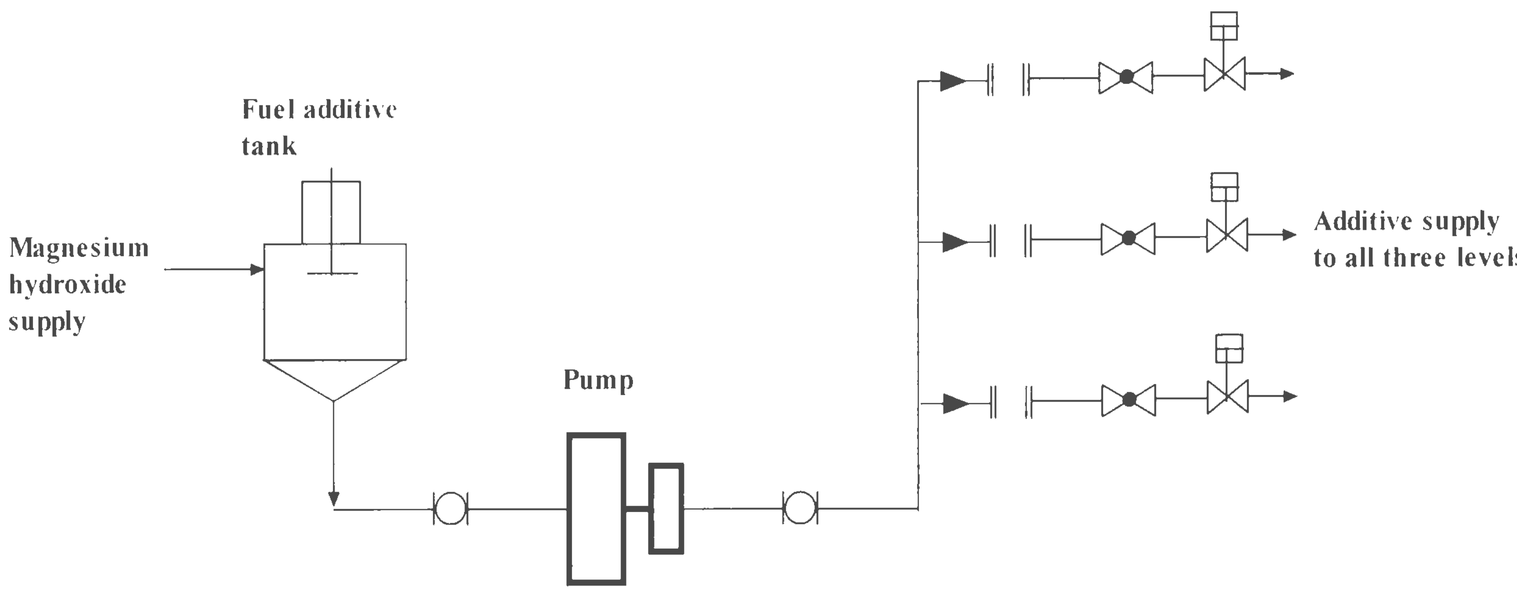
4.7 Heavy oil system



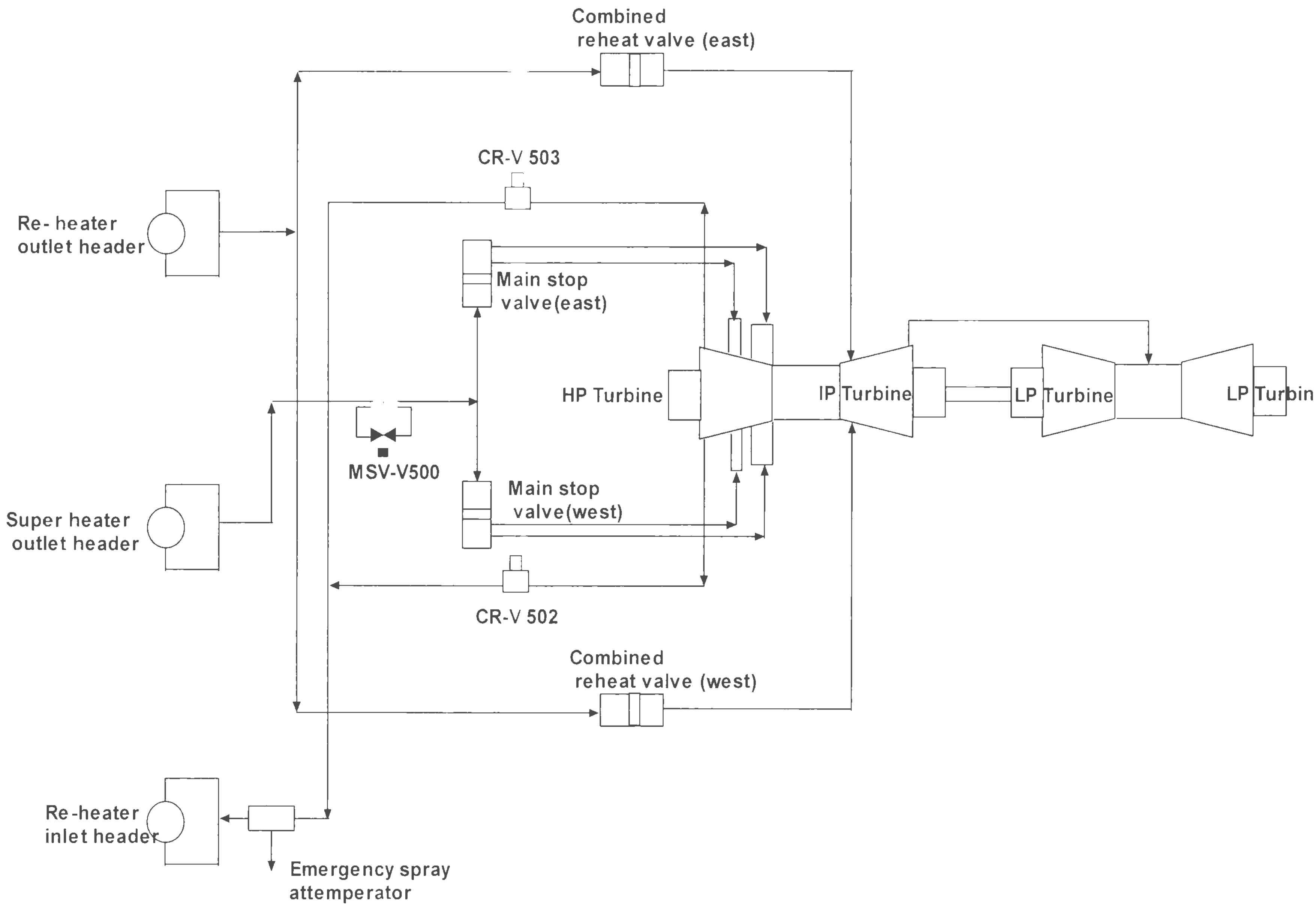
4.8 Light oil system



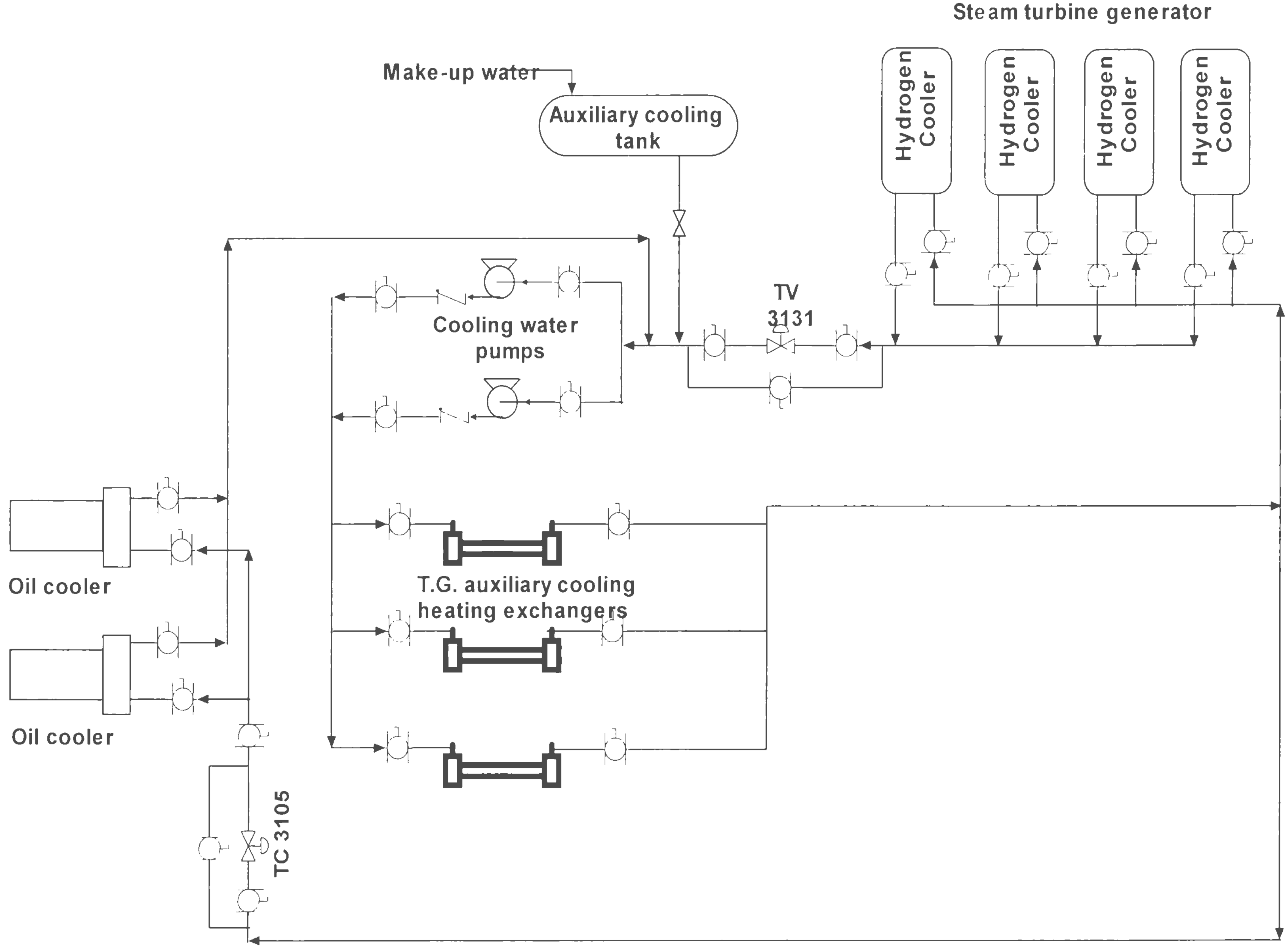
4.9 Fuel additive system



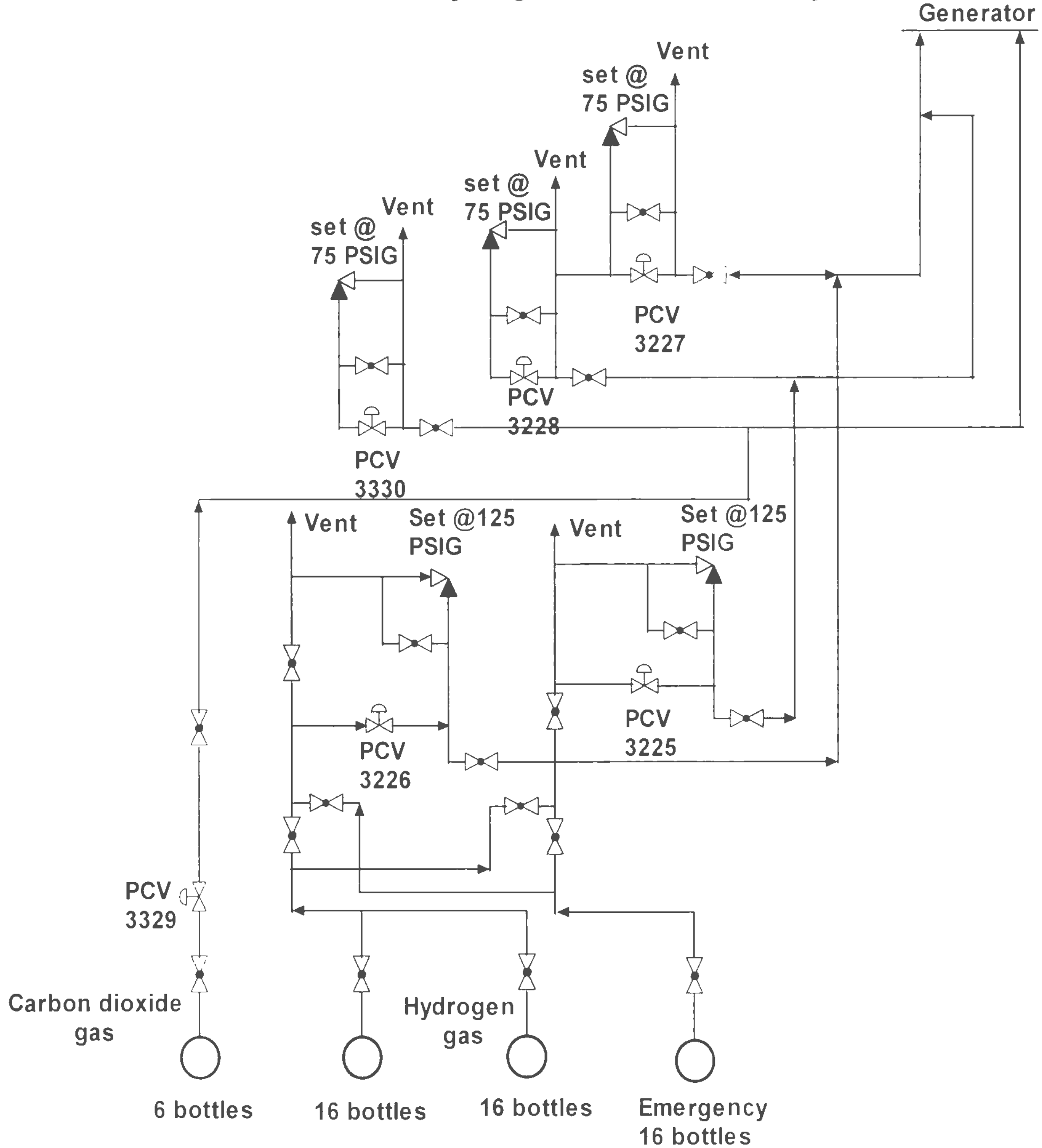
4.10 Main steam and re-heat system



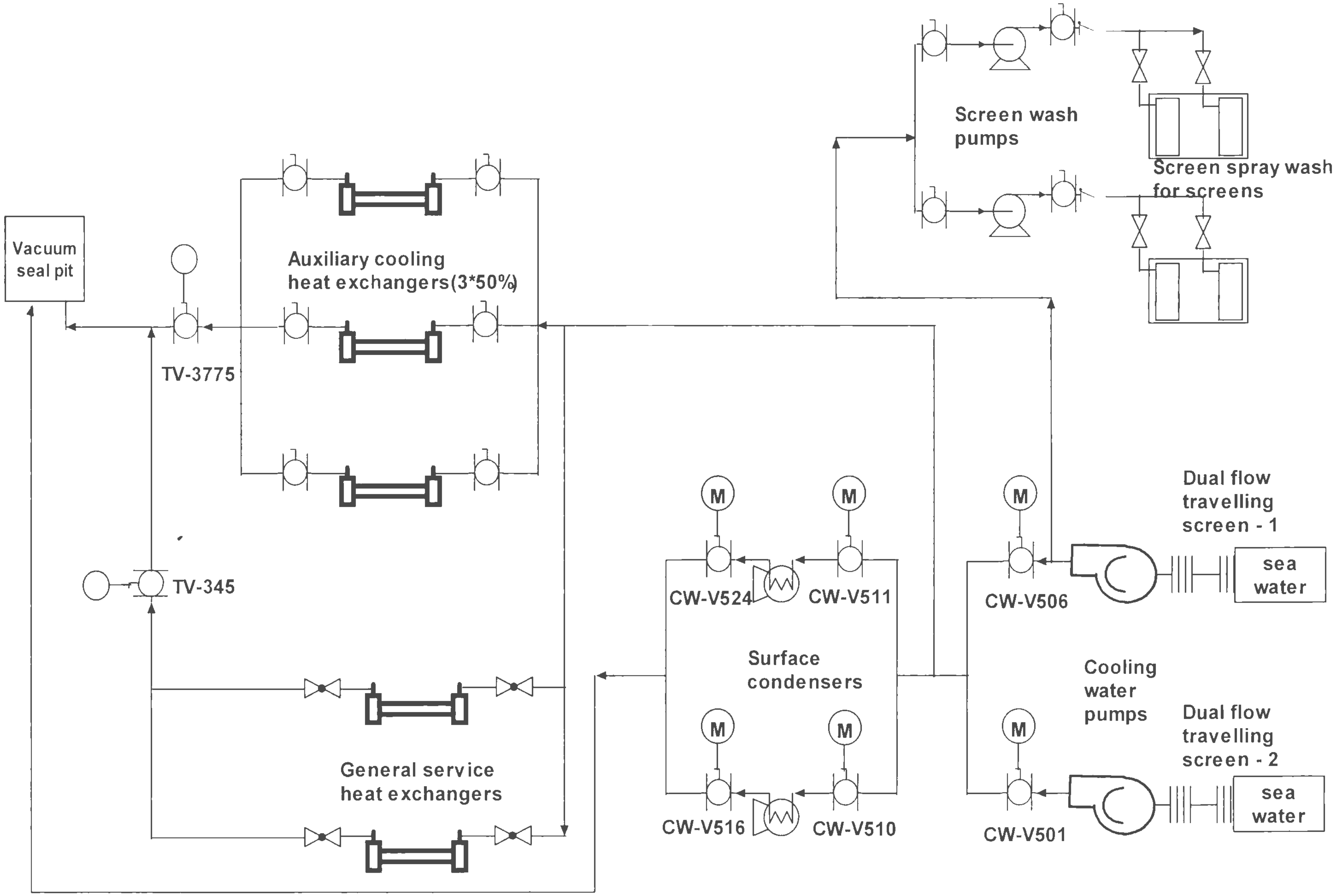
4.11 Turbine generator auxiliary cooling system



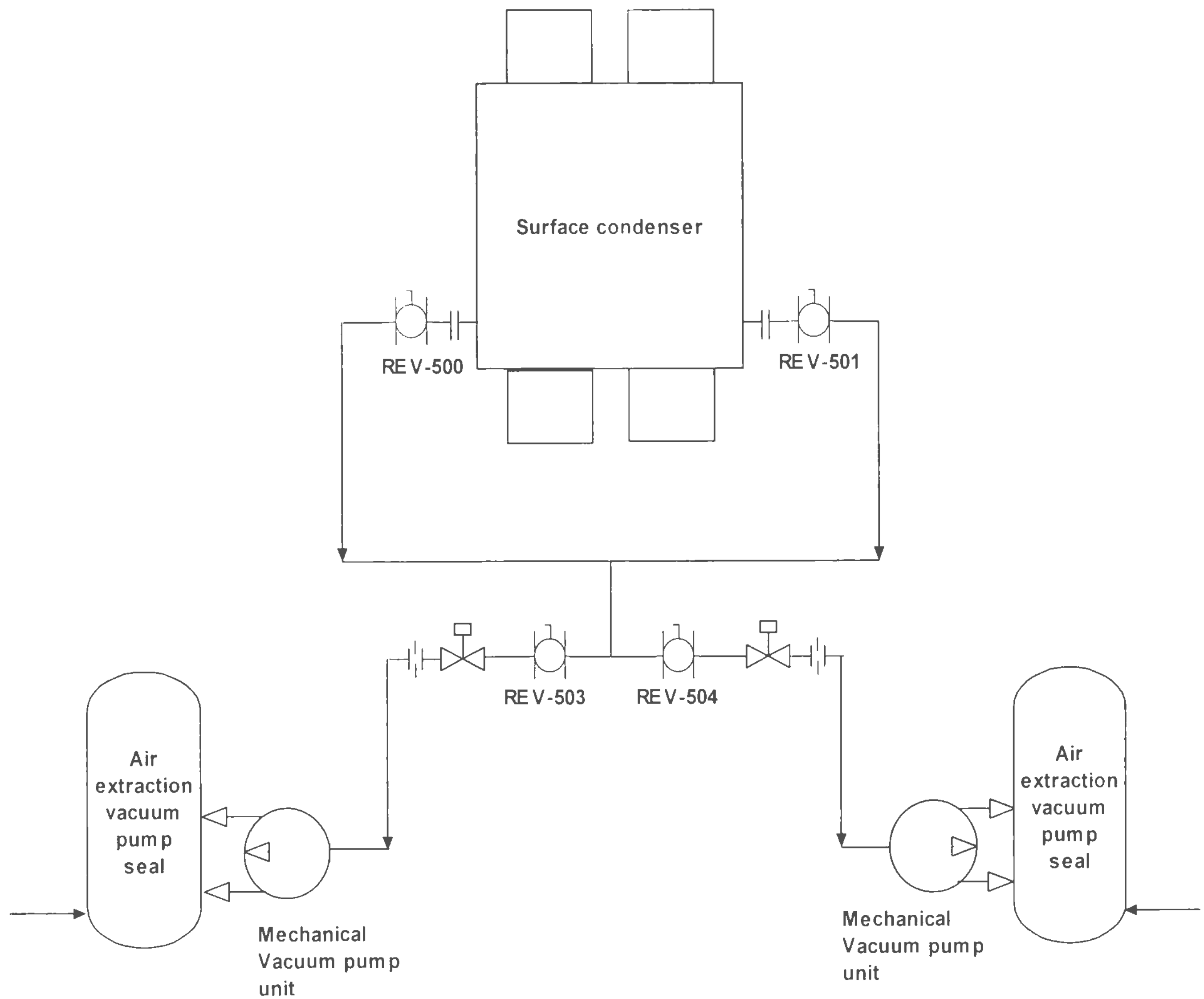
4.12 Generator hydrogen & carbon dioxide systems



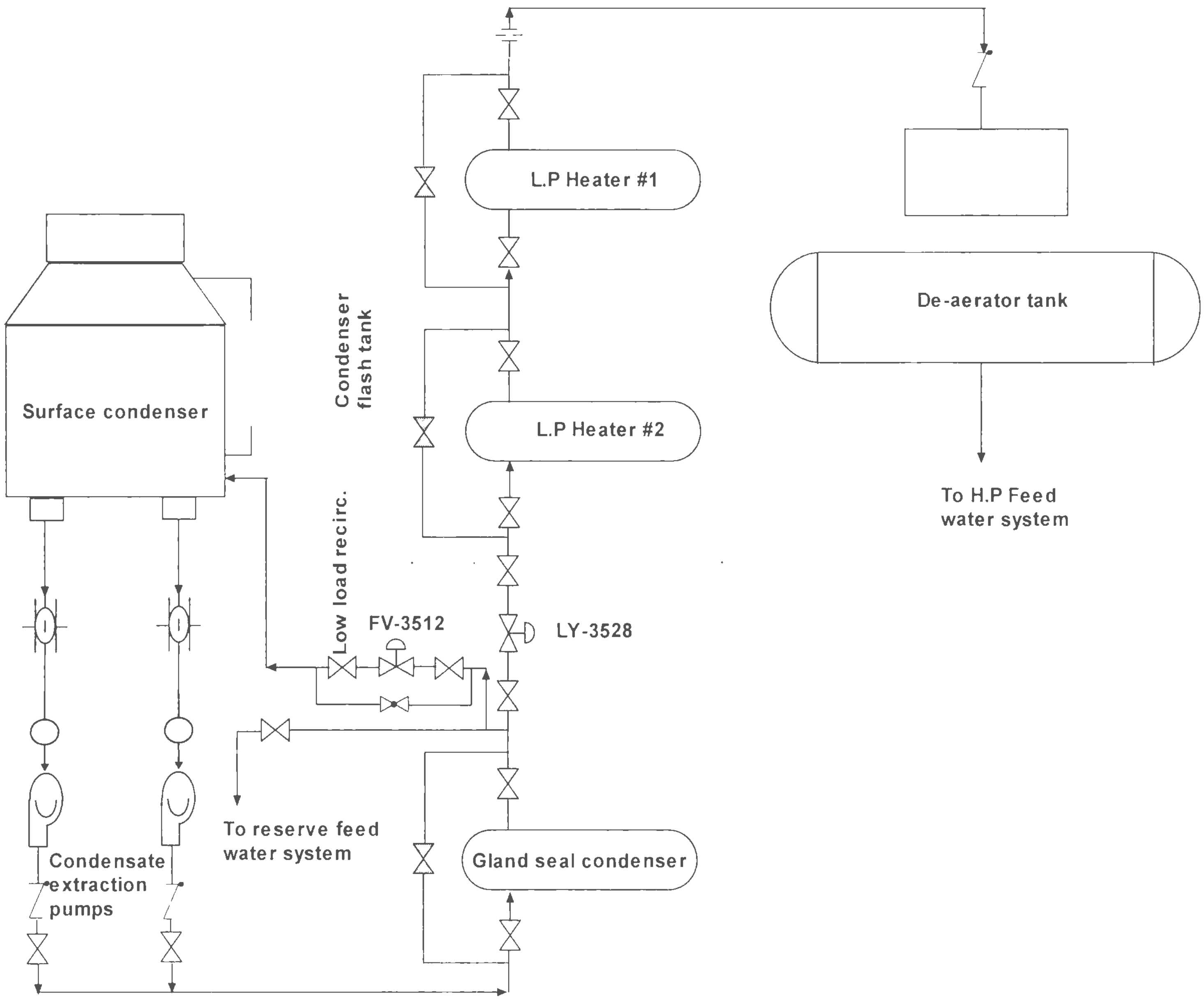
4.13 Circulating water and screen water wash



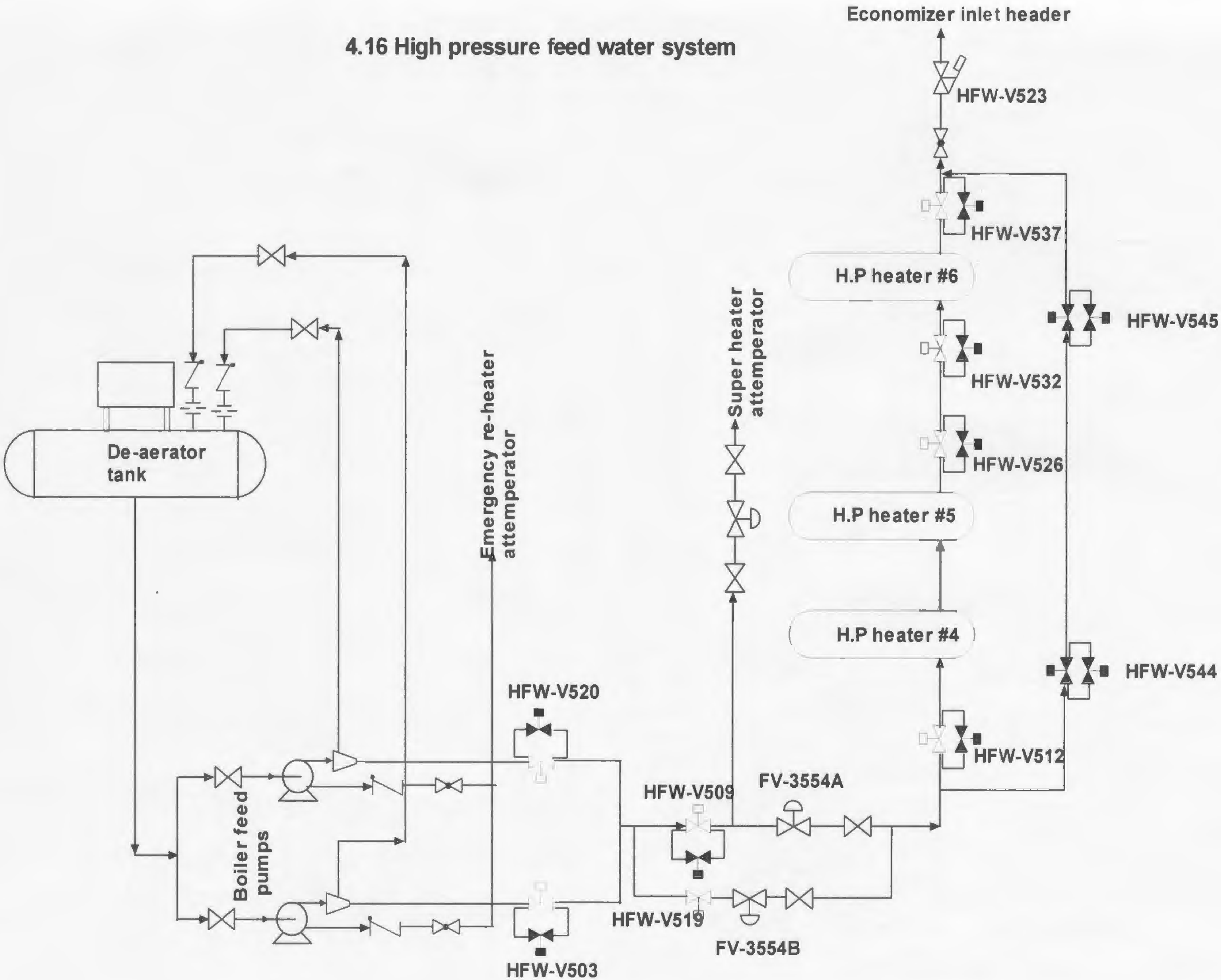
4.14 Condenser air extraction system



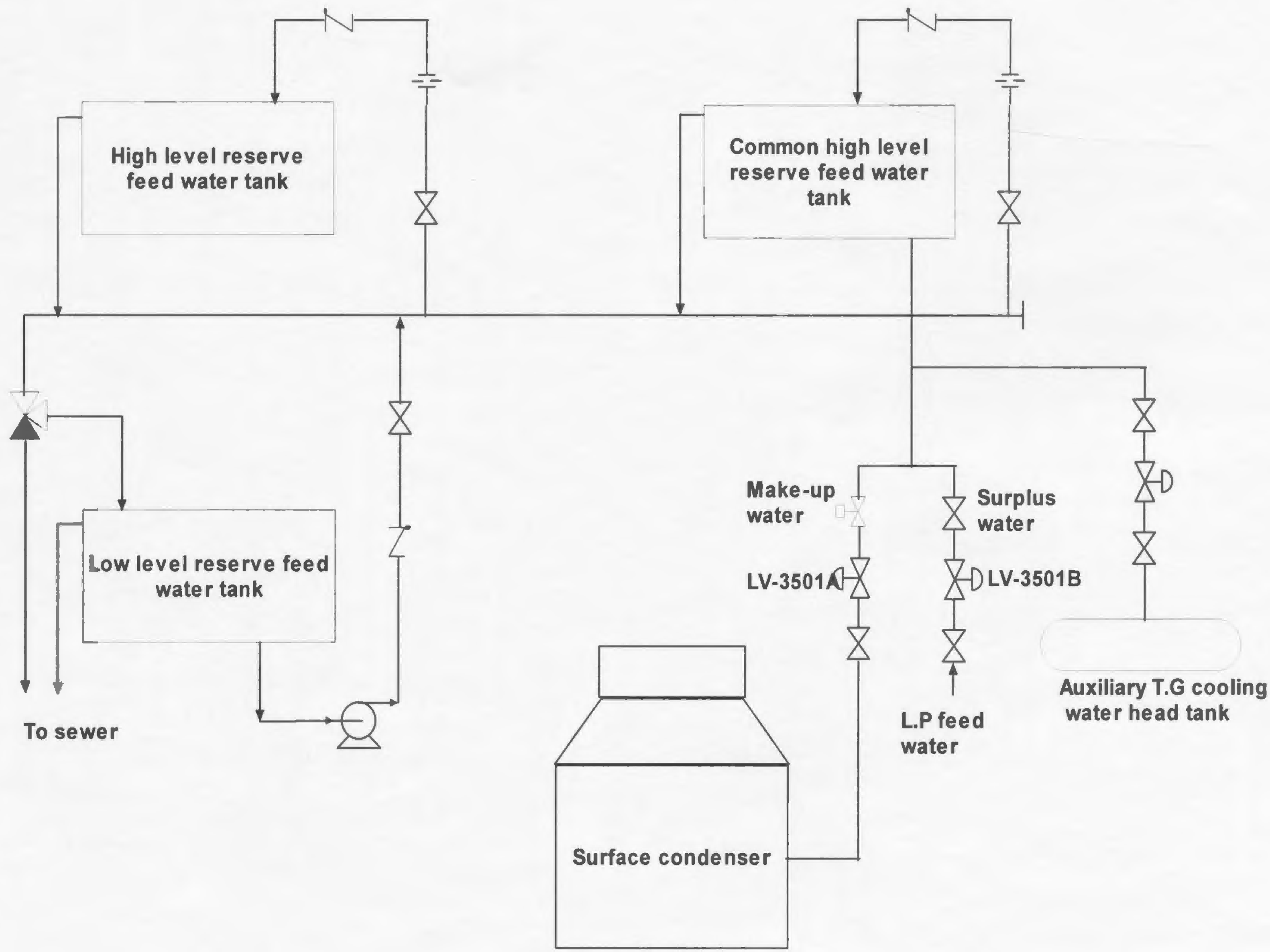
4.15 Low pressure feed water system



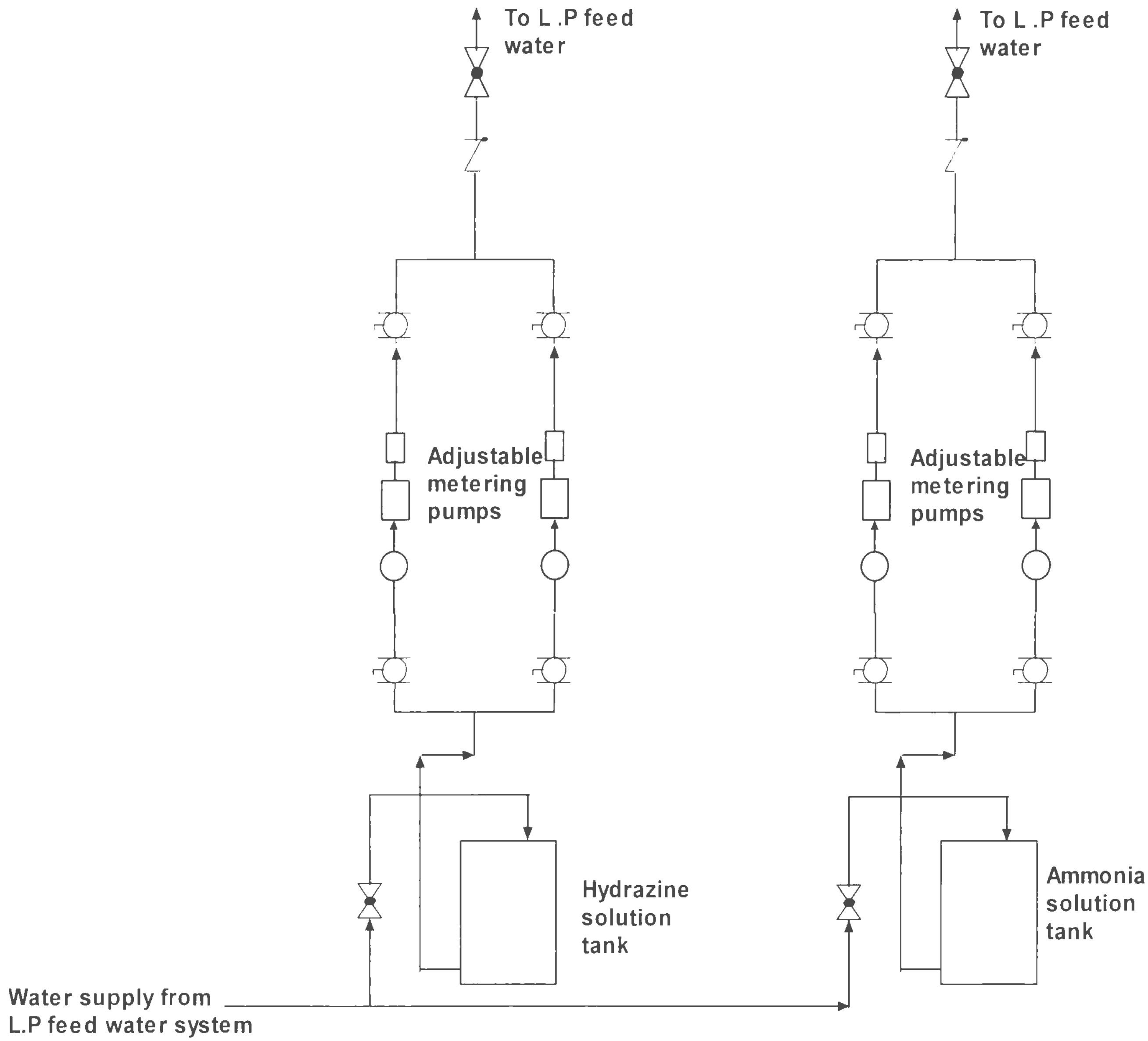
4.16 High pressure feed water system



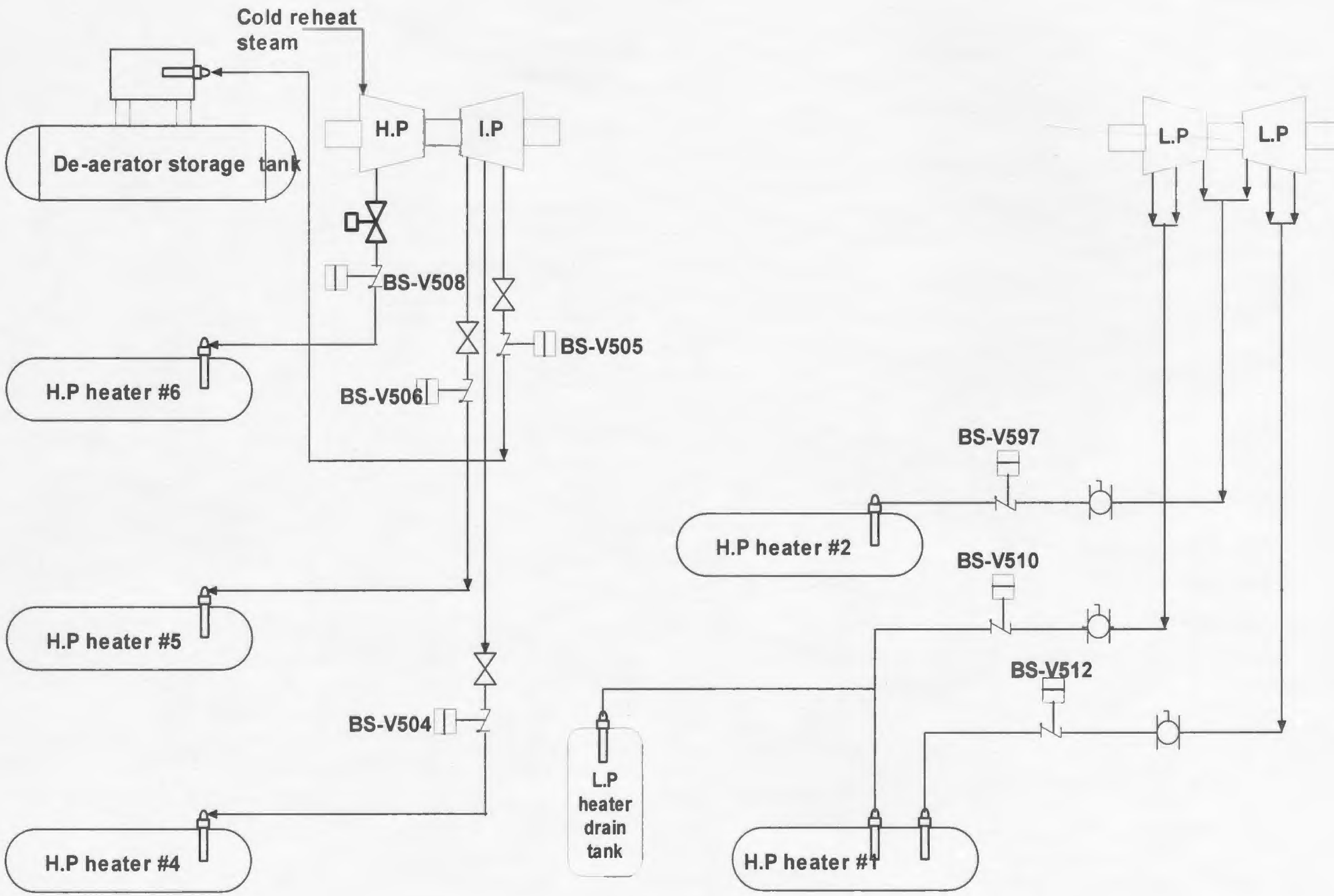
4.17 Reserve feed water system



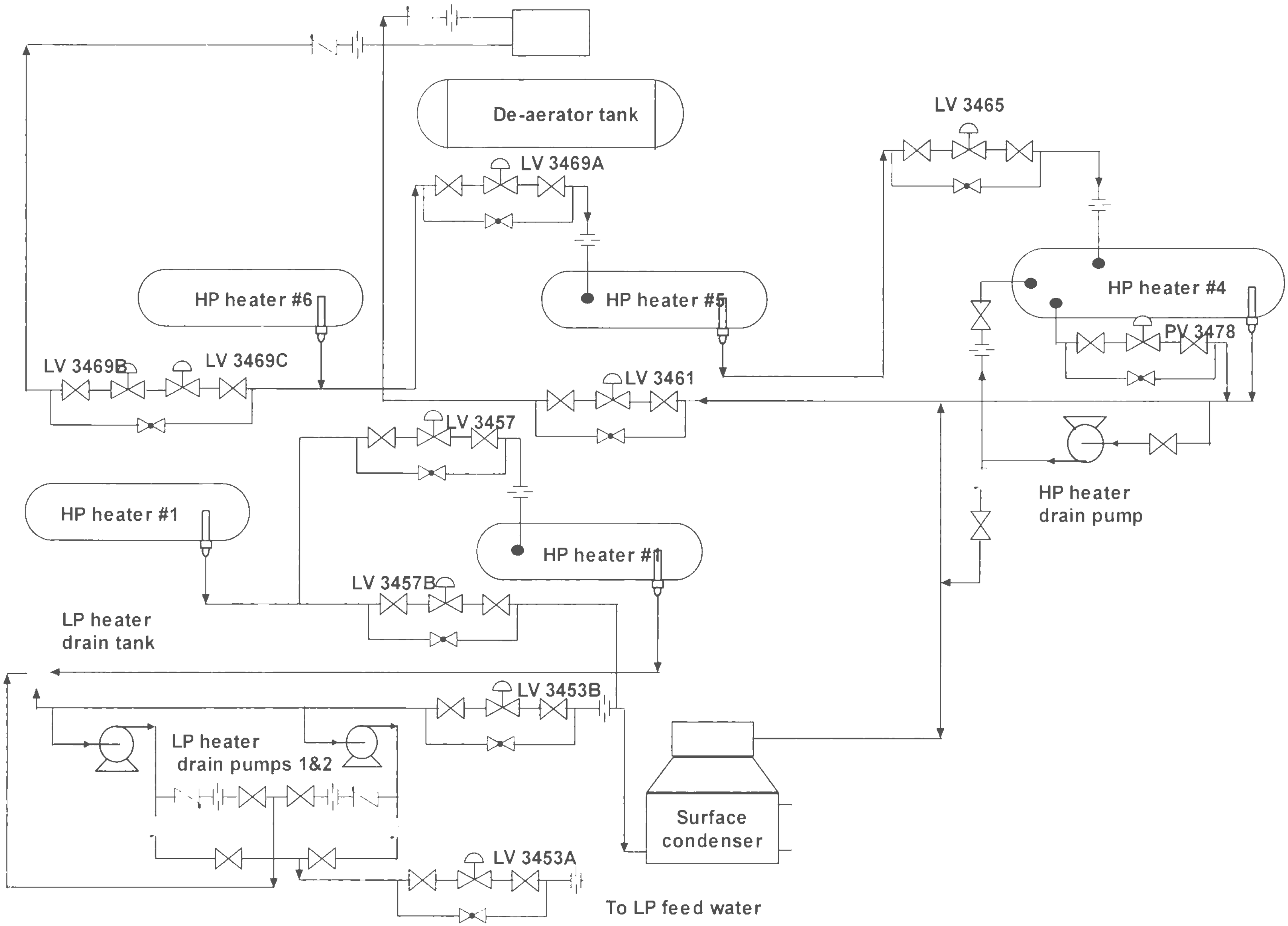
4.18 Chemical feed system



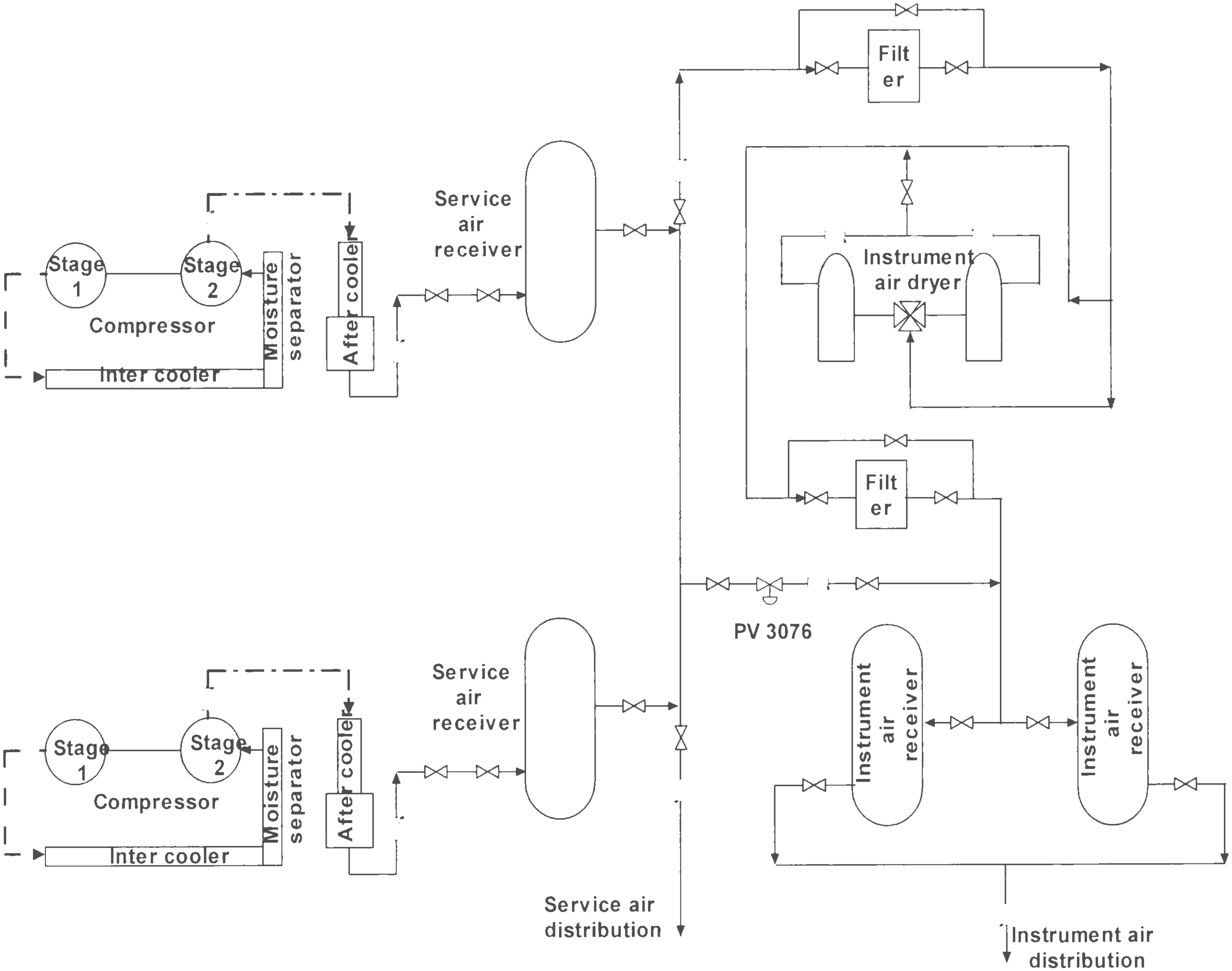
4.19 Bled steam system



4.20 Feed water drains system

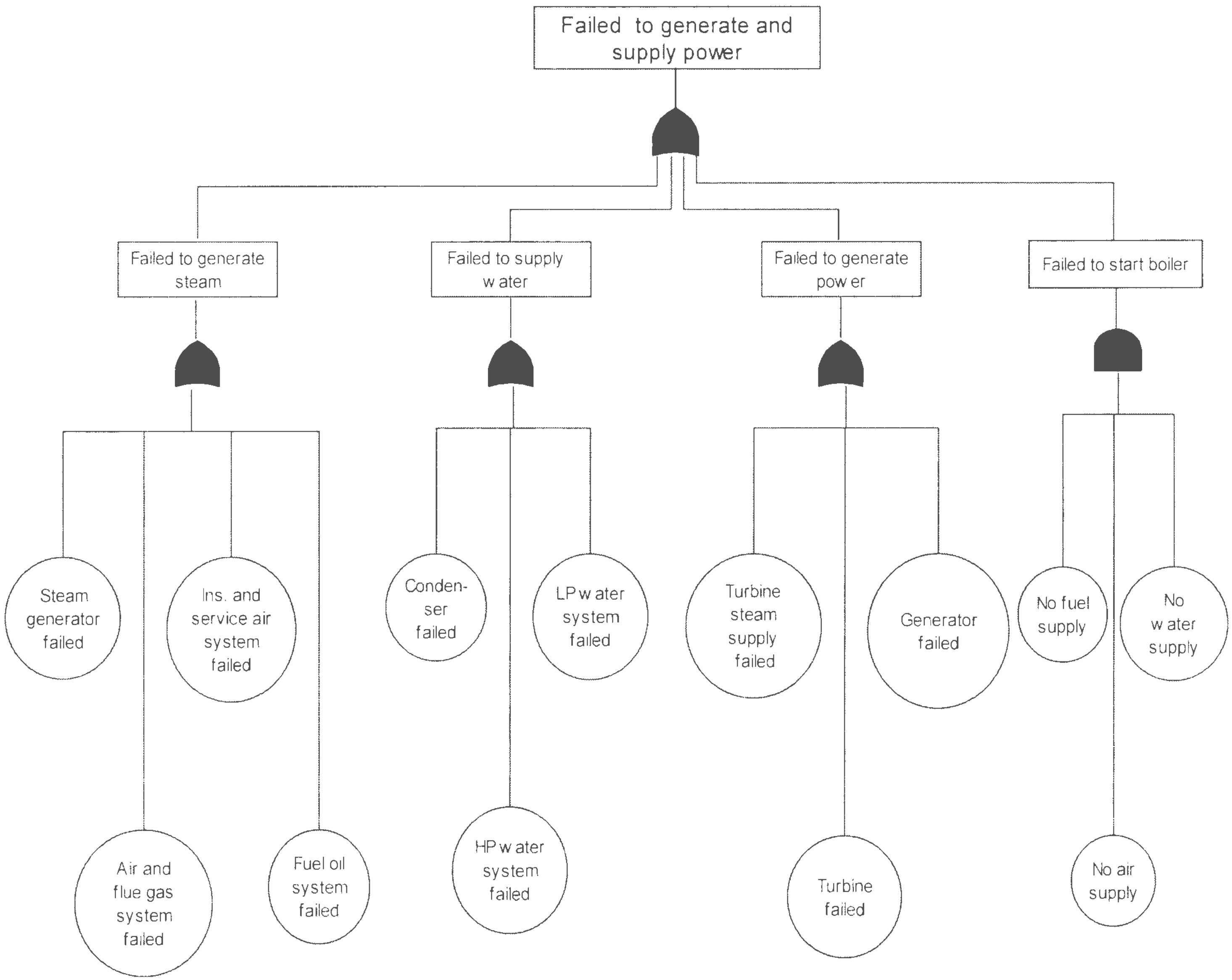


4.21 Service air and Instrument air supply

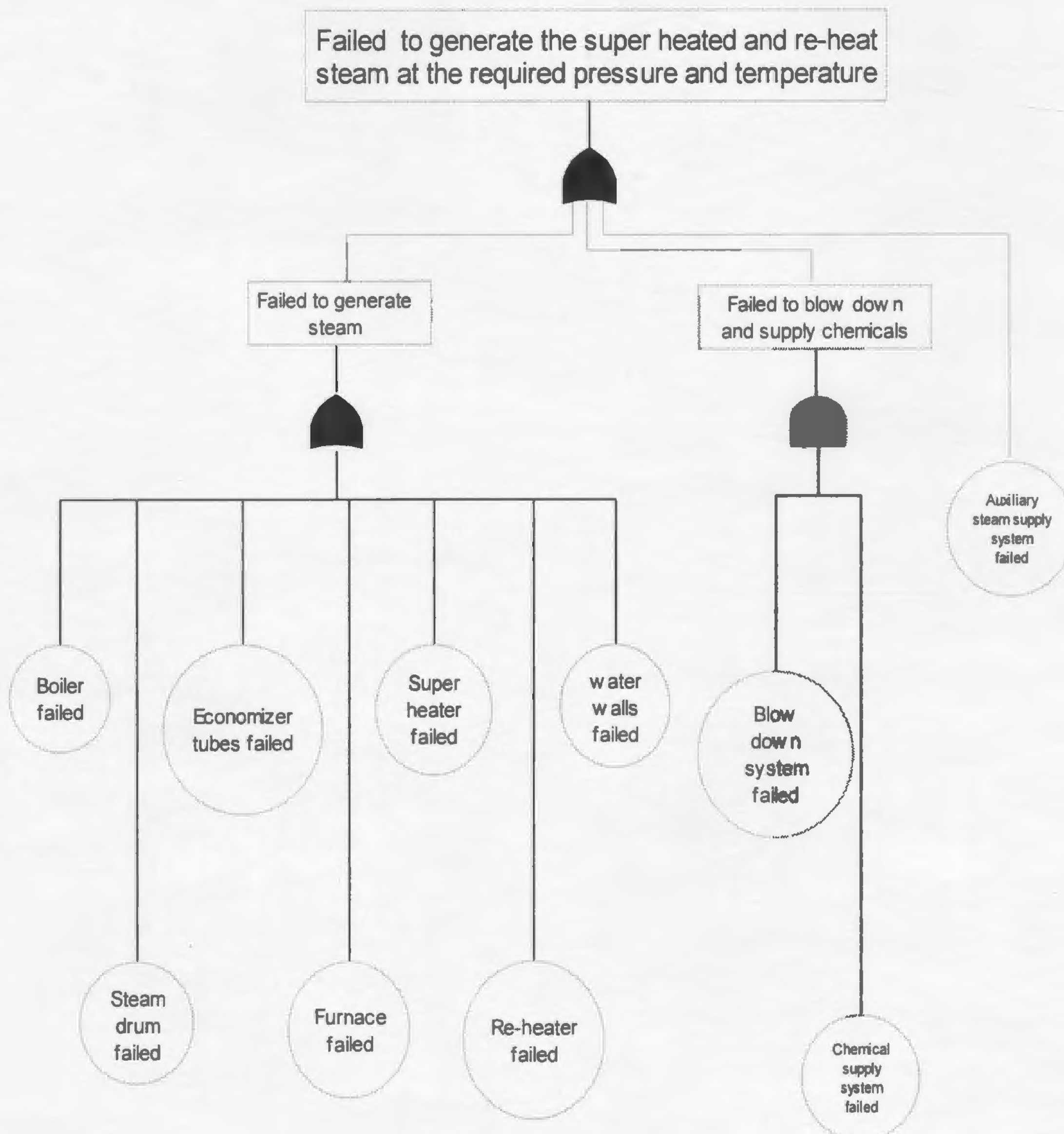


Appendix C – Fault trees

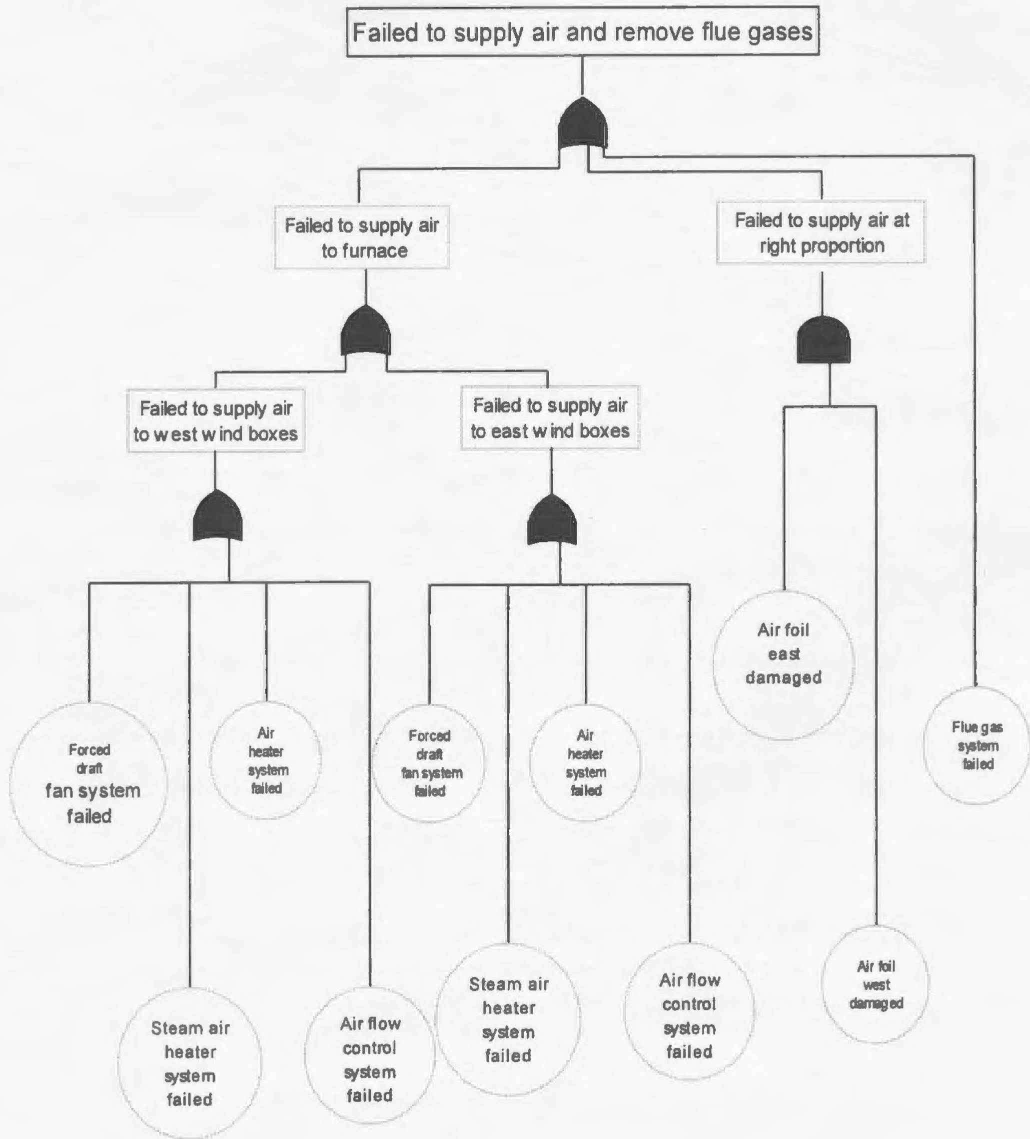
5. Unit-3 power plant



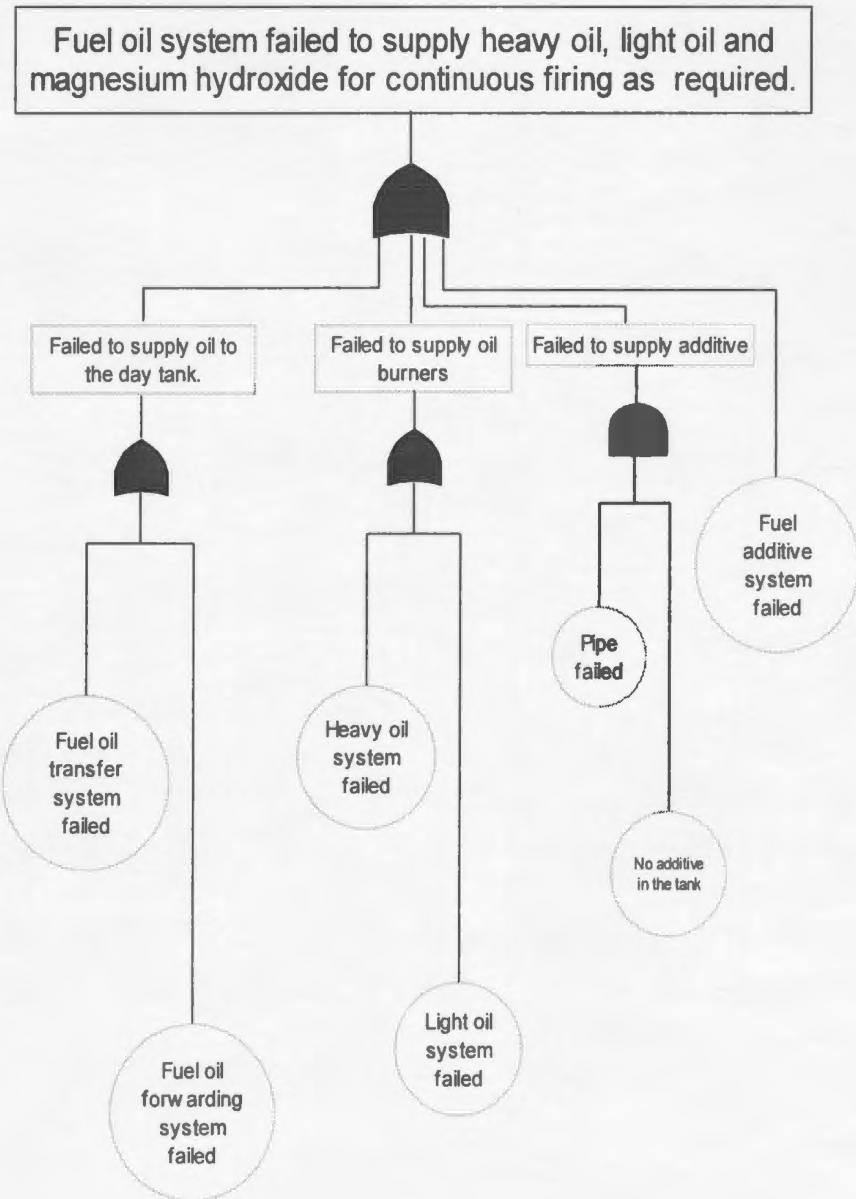
5.1 Steam generator



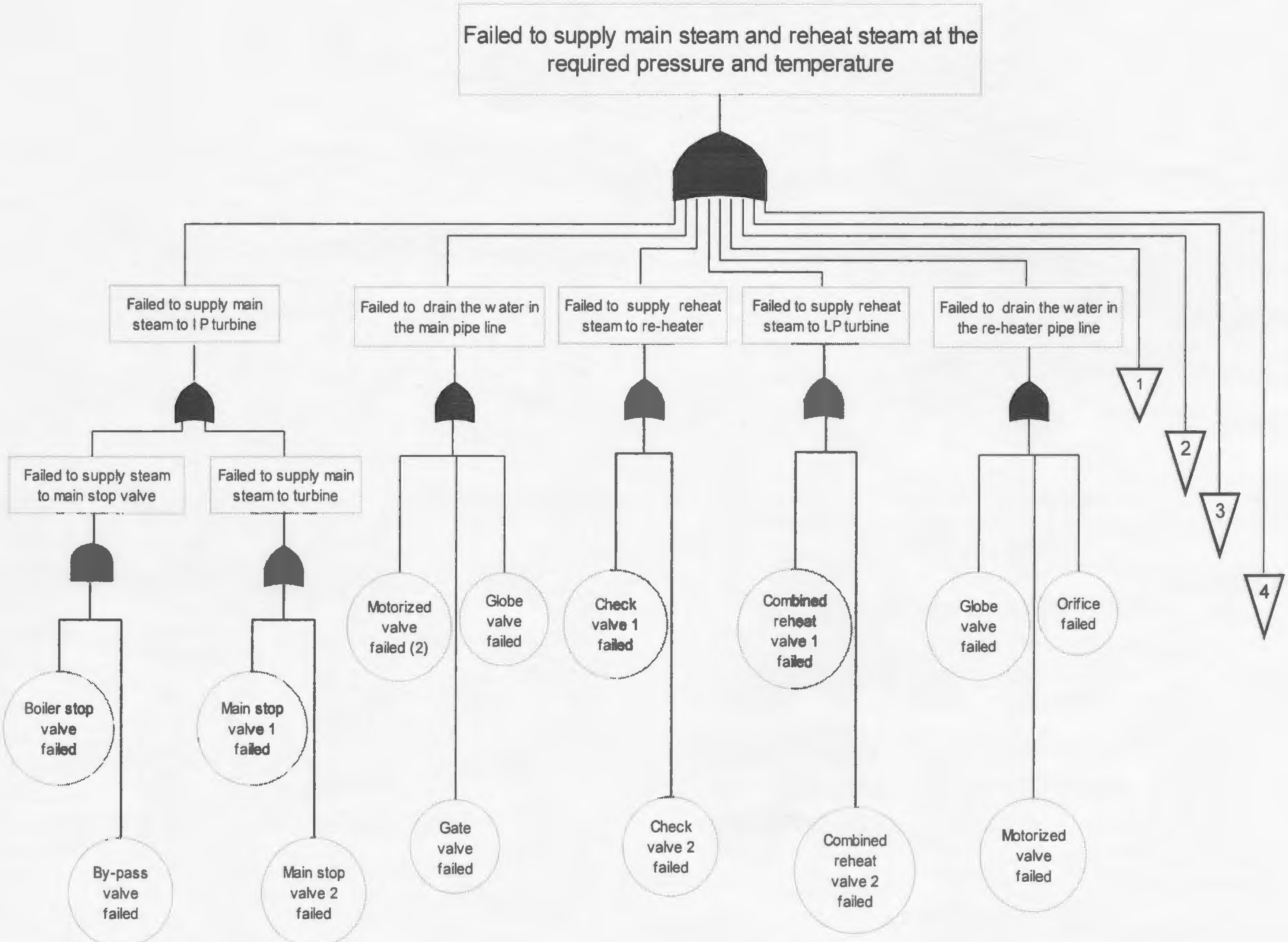
5.2 Air and Flue gas system



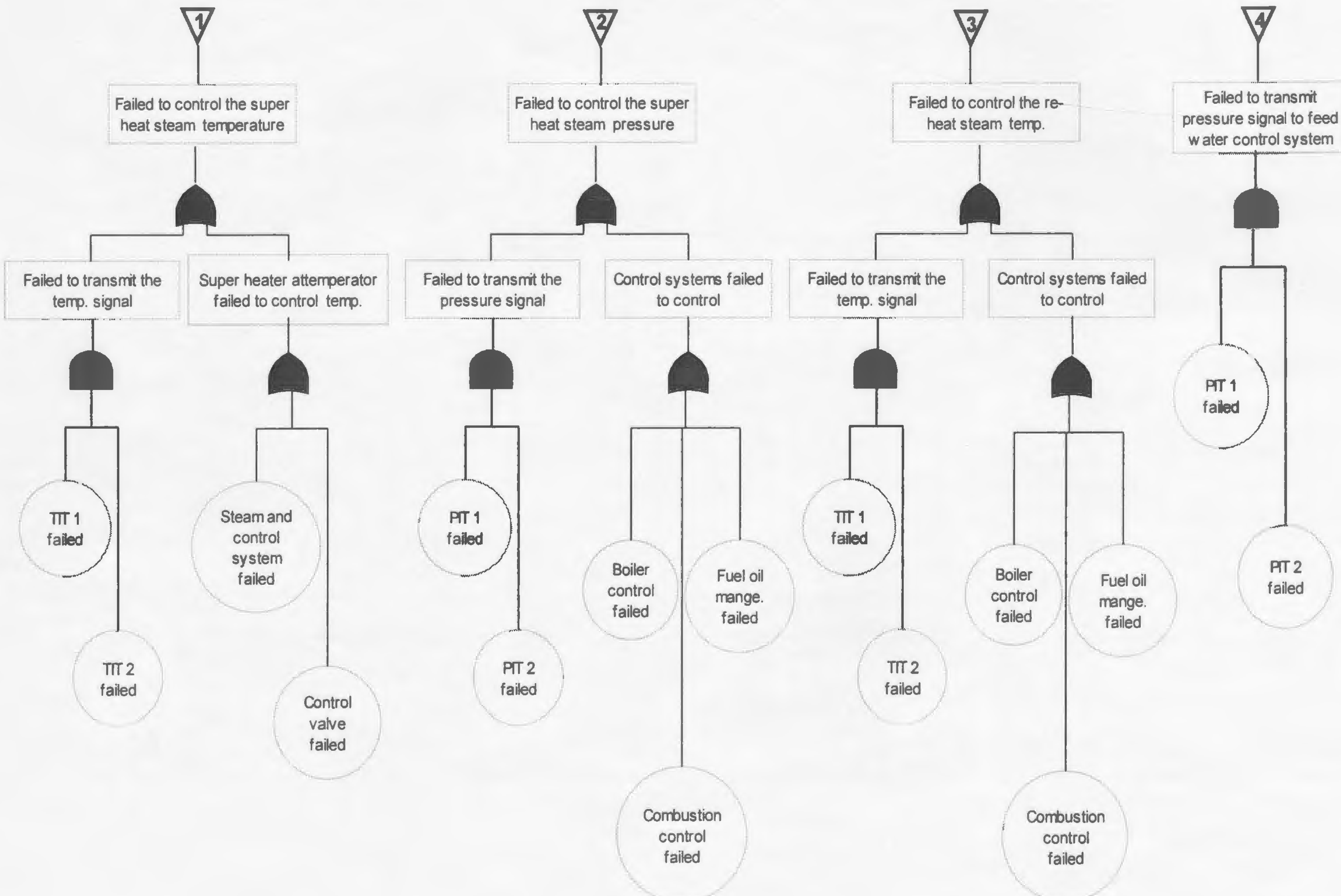
5.3 Fuel oil system



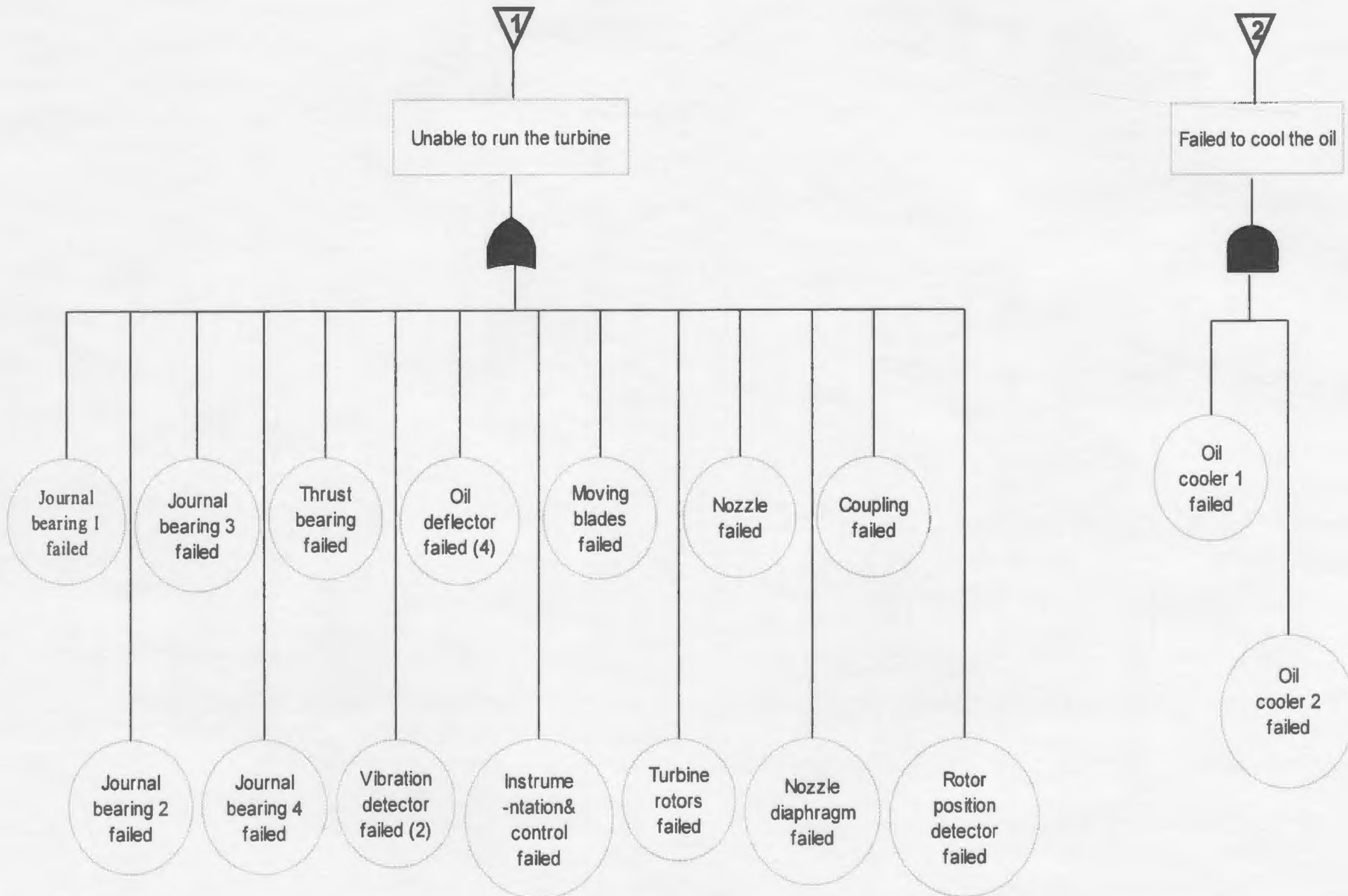
5.4 (a) Turbine- Steam supply



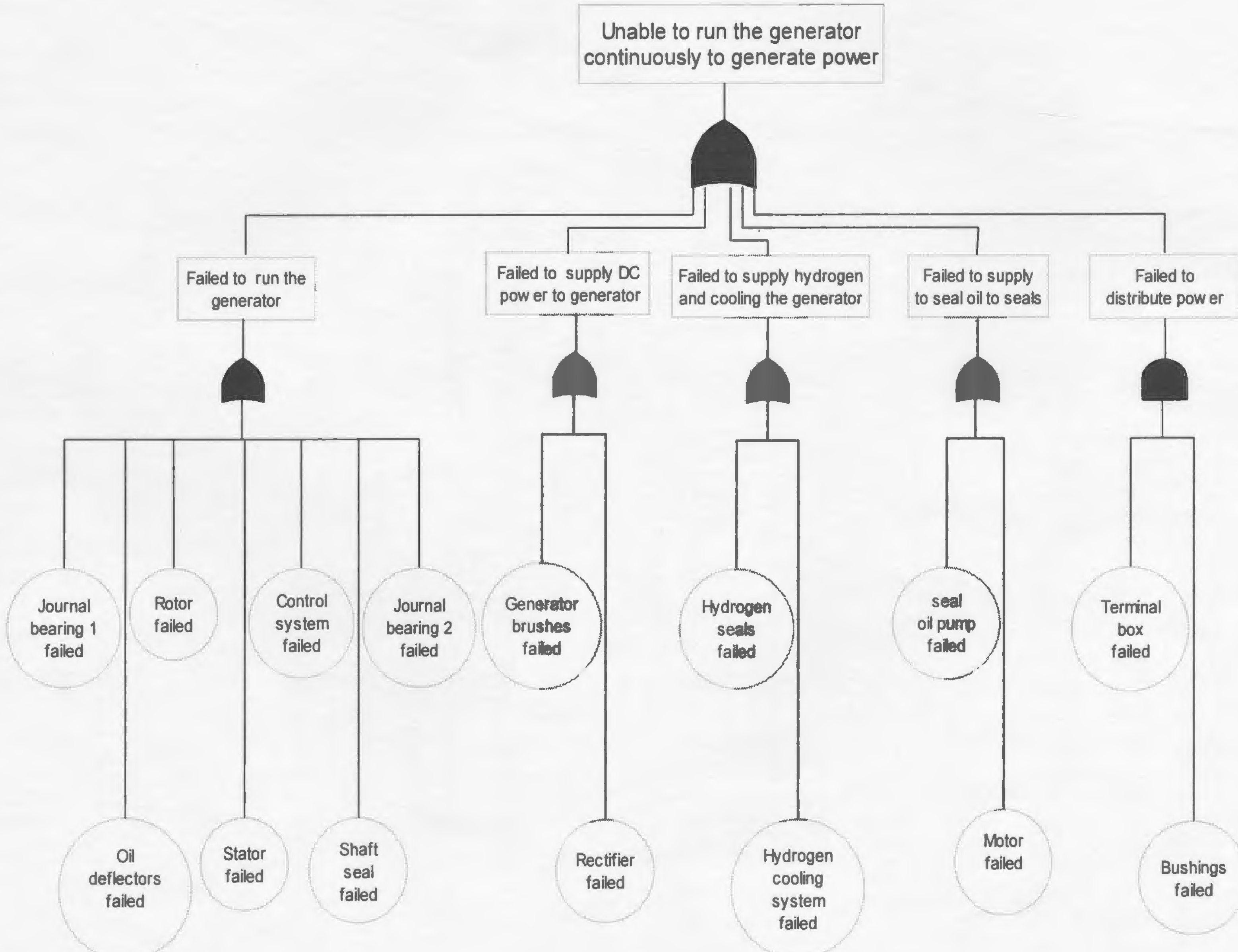
5.4 (a) Turbine- Steam supply



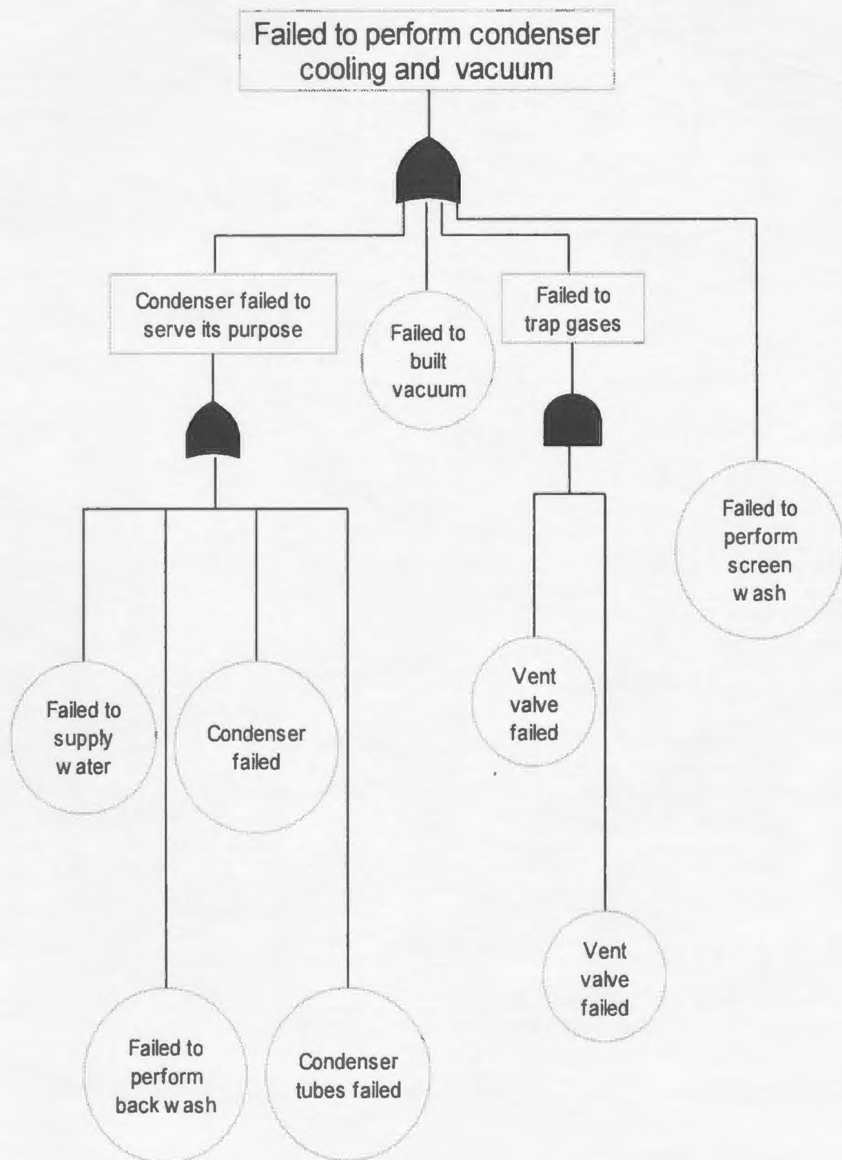
5.4 (b) Turbine- Rotating system



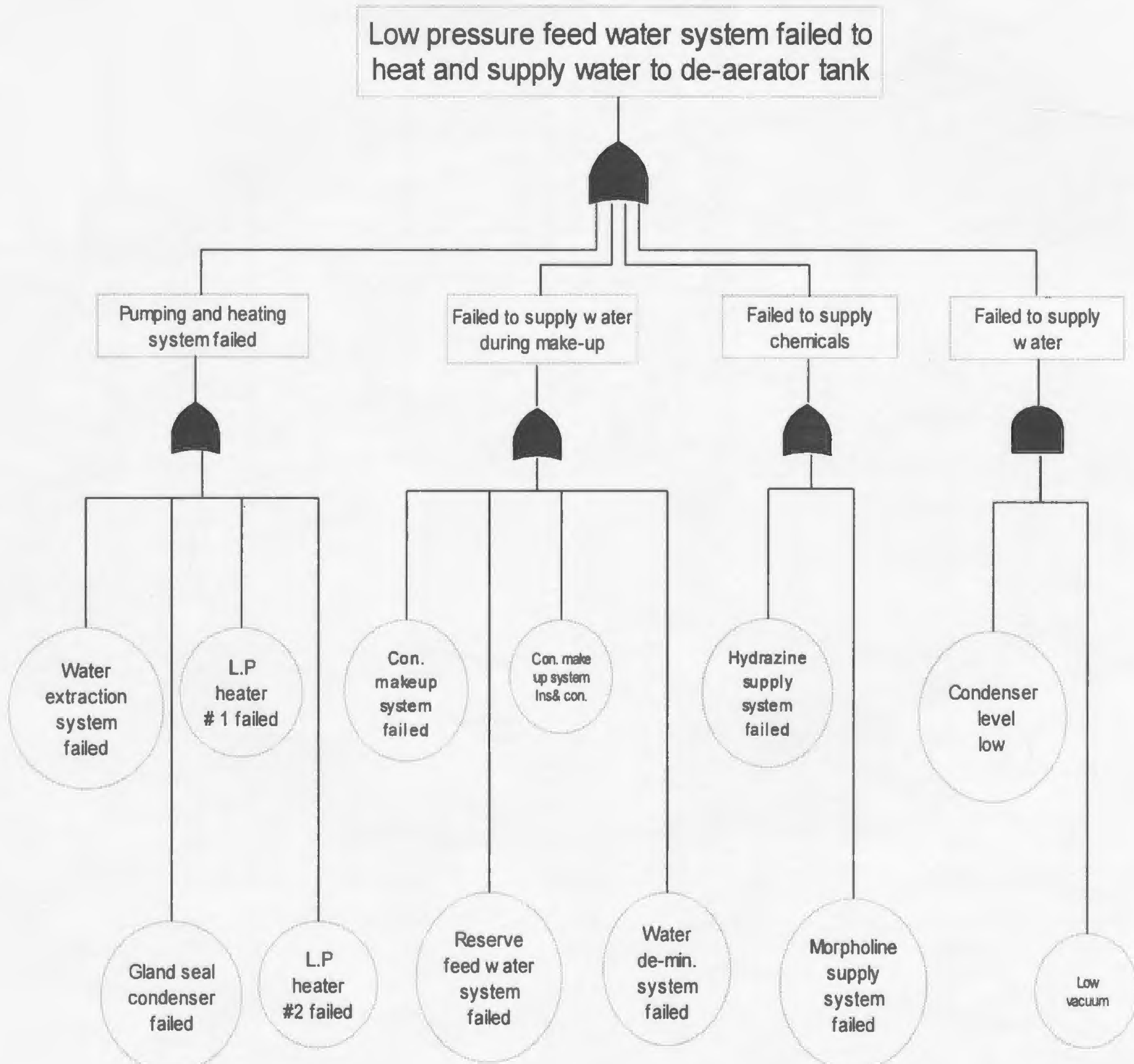
5.5 Generator



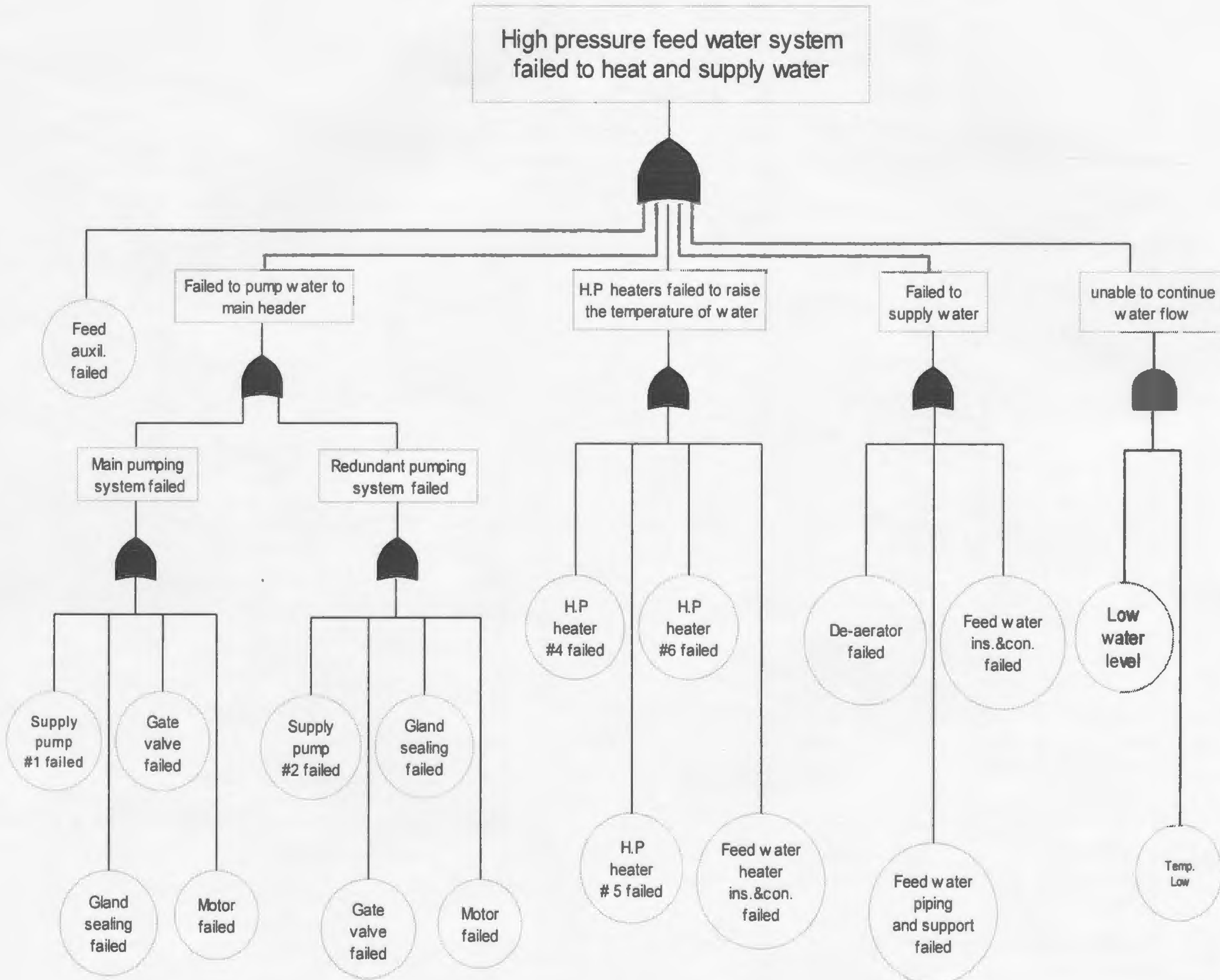
5.6 Condenser



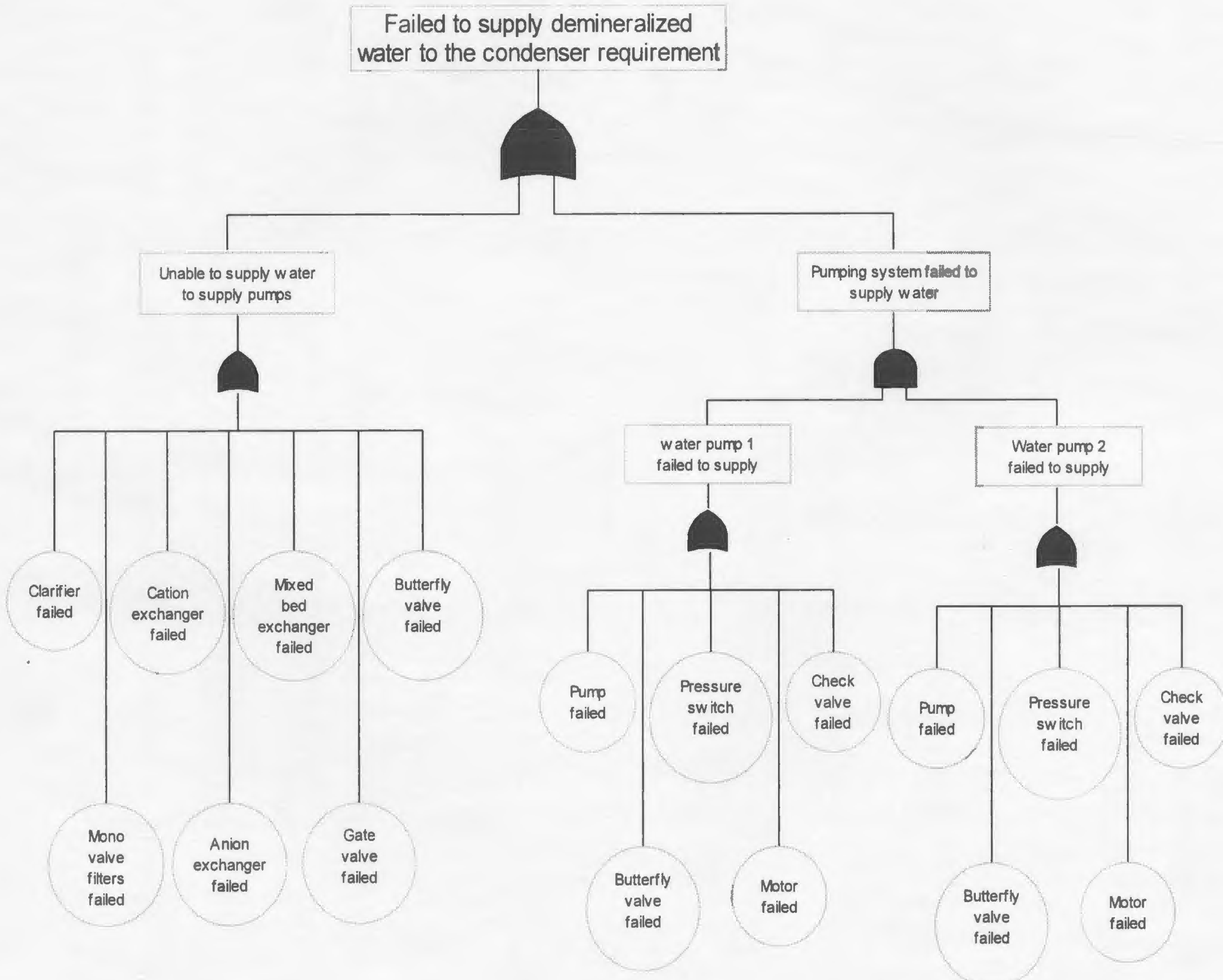
5.7.2 Low pressure feed water system



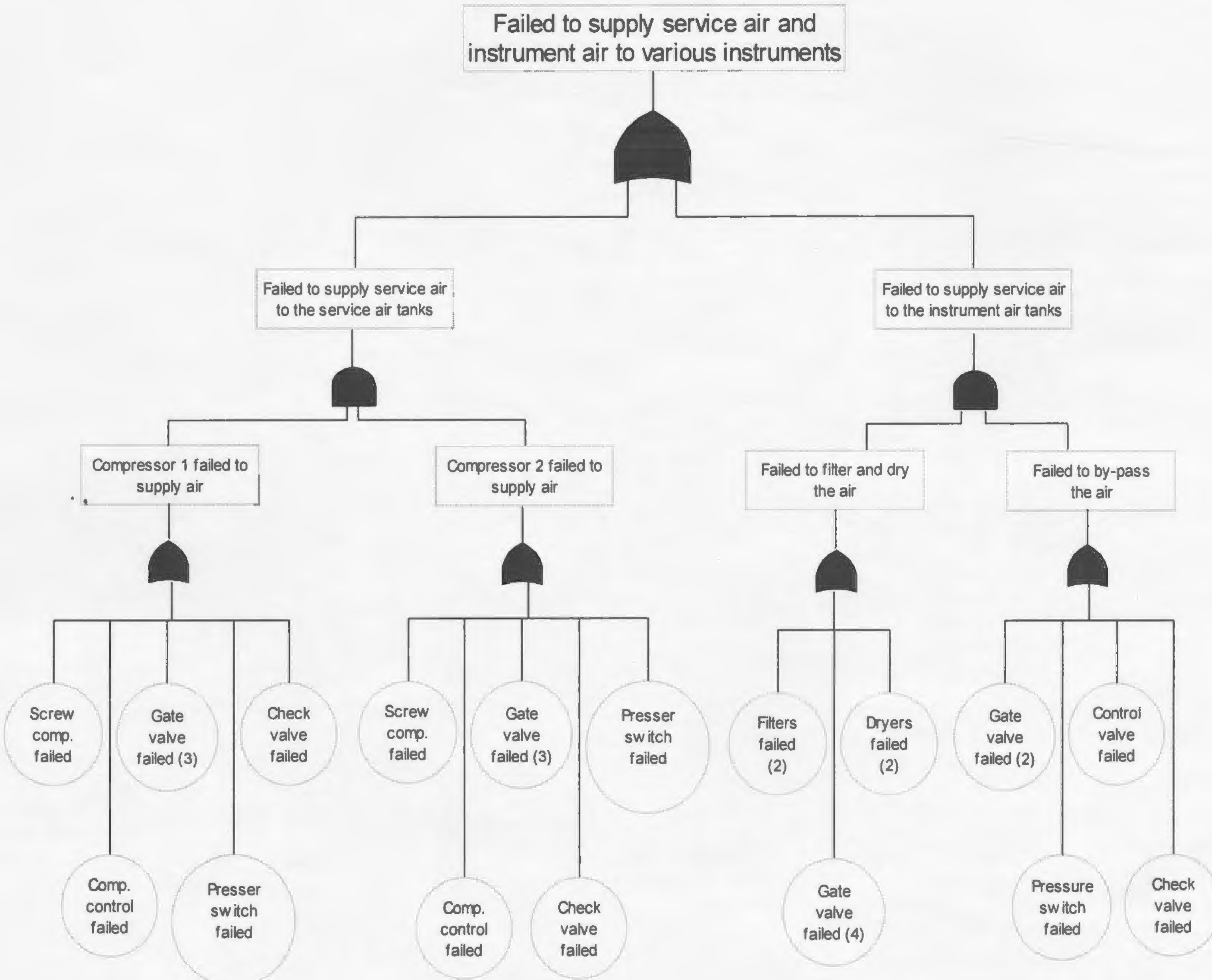
5.7.3 High pressure feed water system



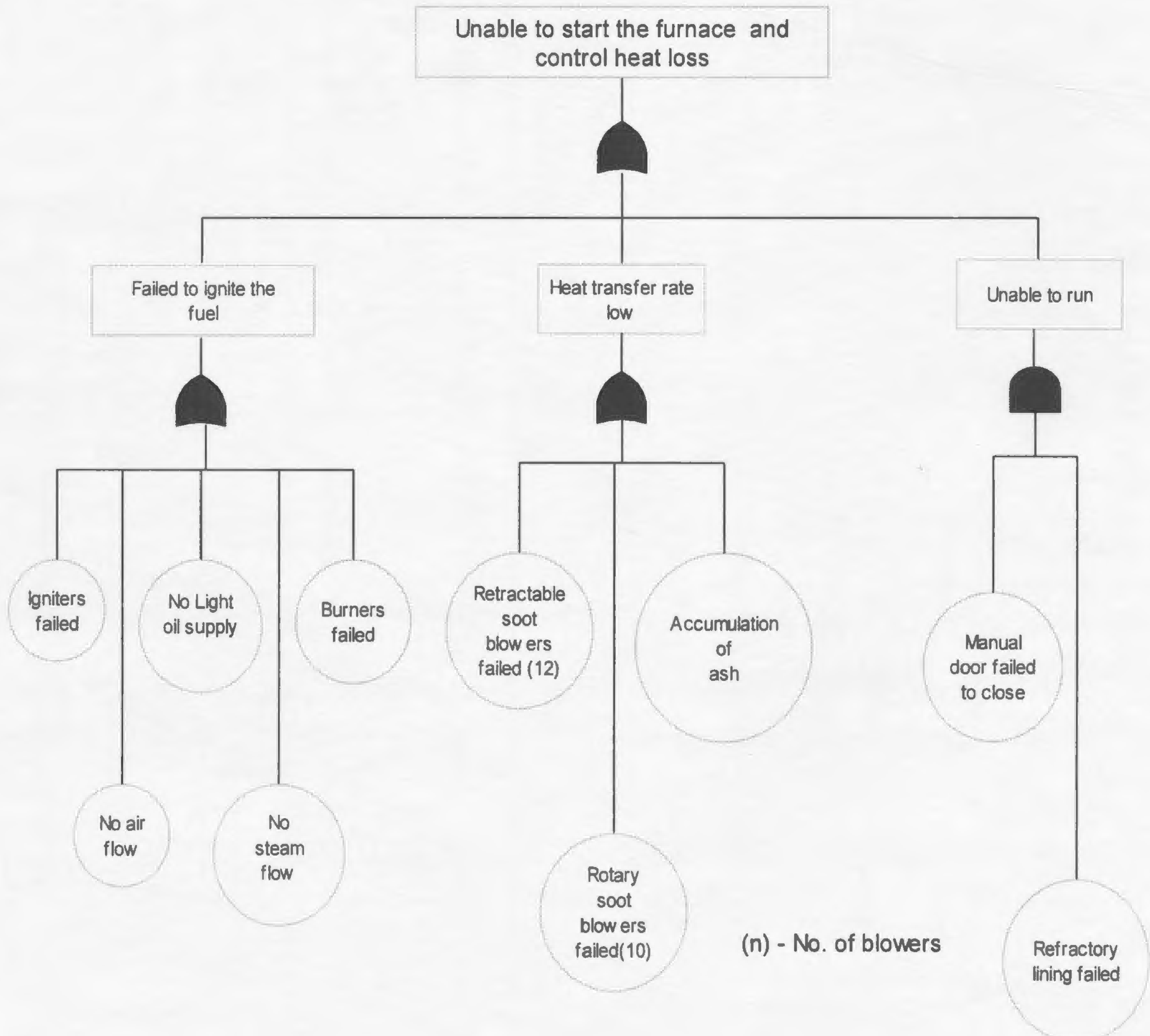
5.8 Water de-mineralization system



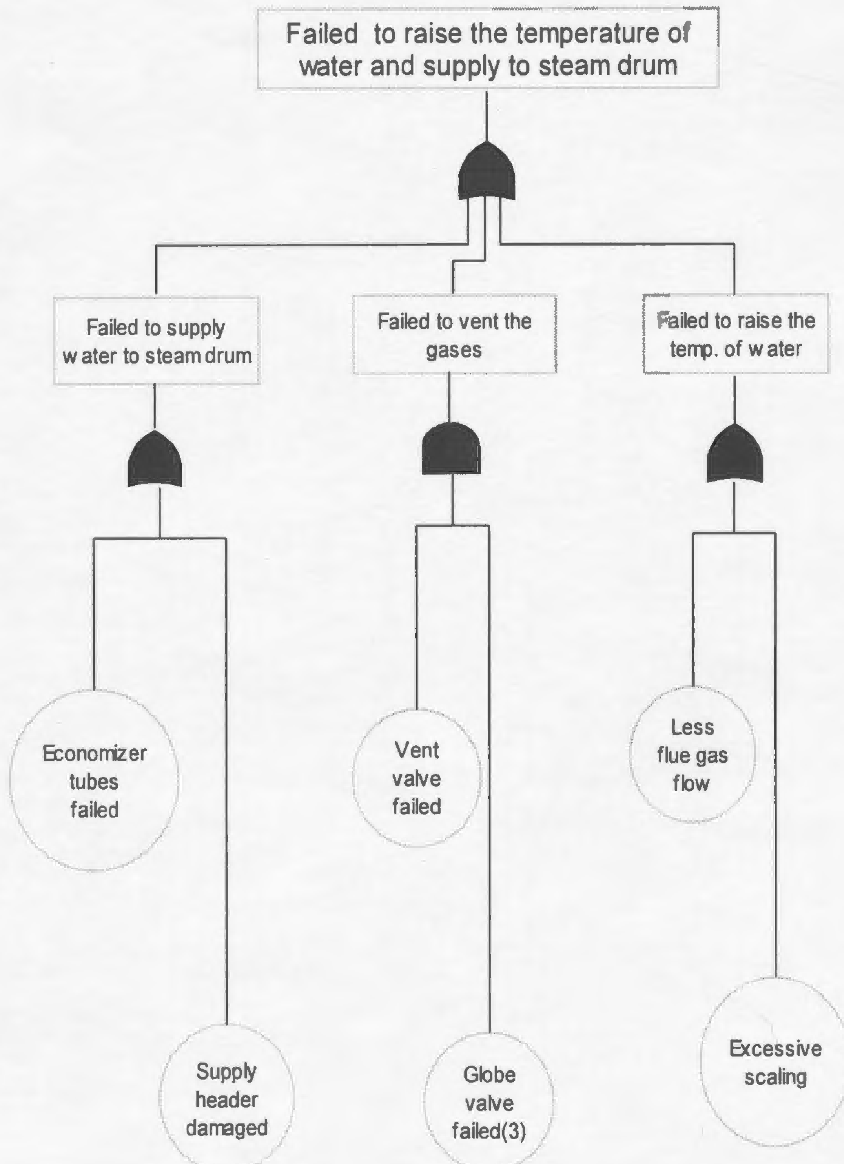
5.9 Instrument and service air system



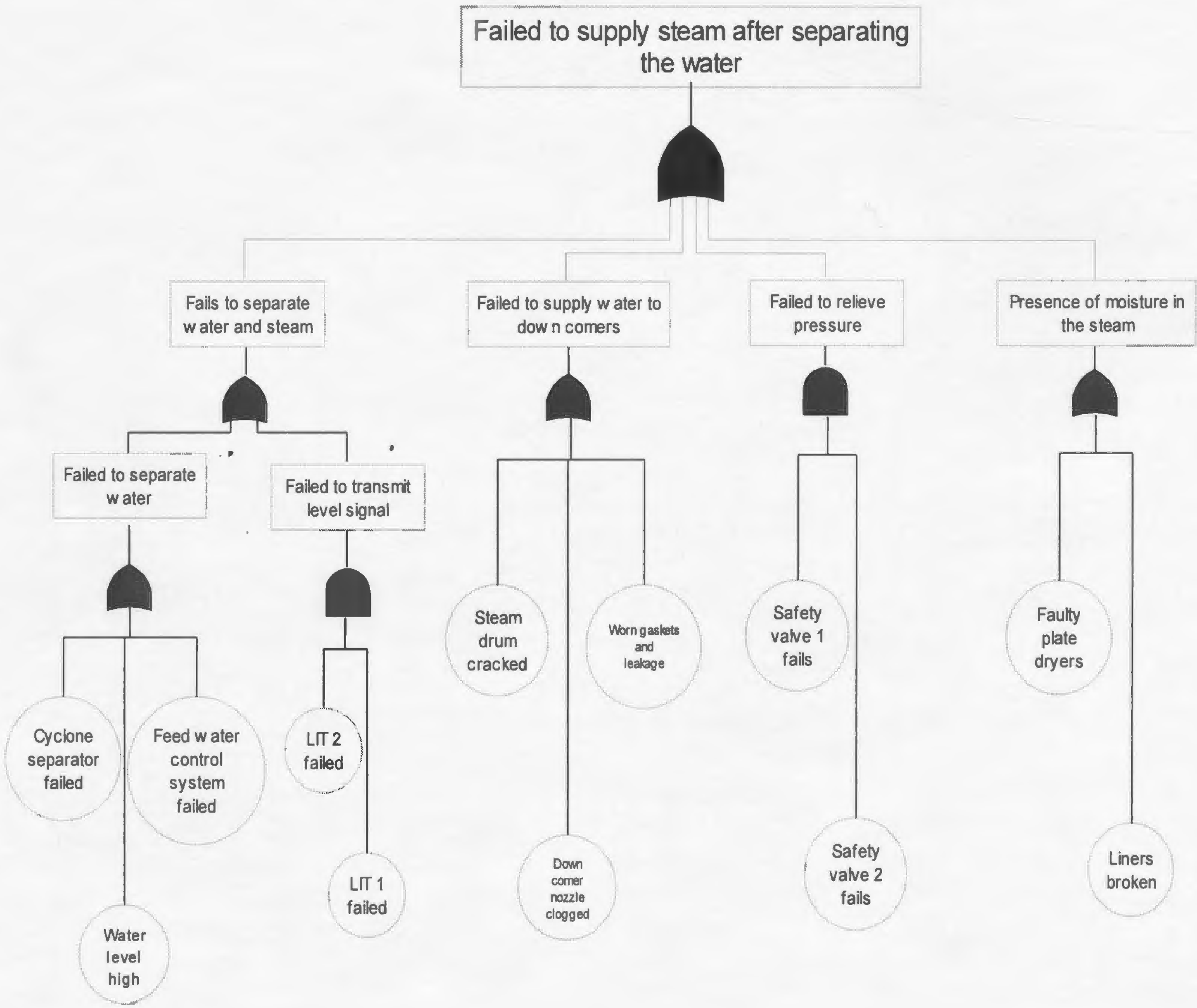
5.1.1 Steam generator-Furnace



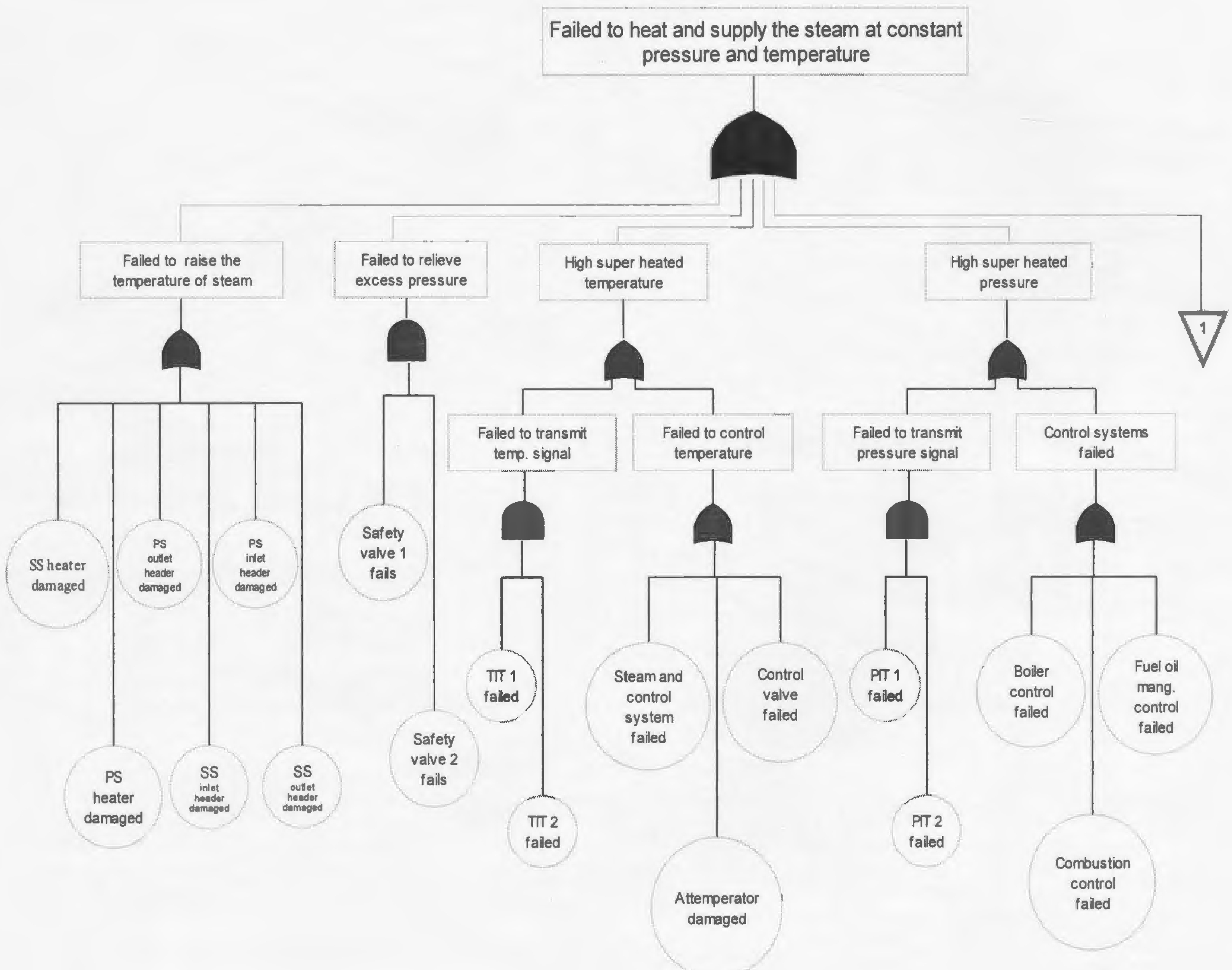
5.1.2 Steam generator- Economizer



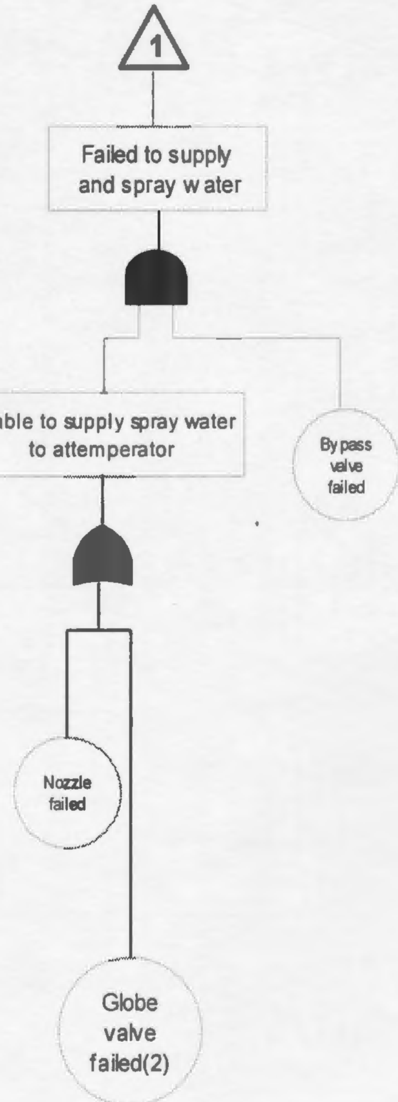
5.1.3 Steam generator - Steam drum



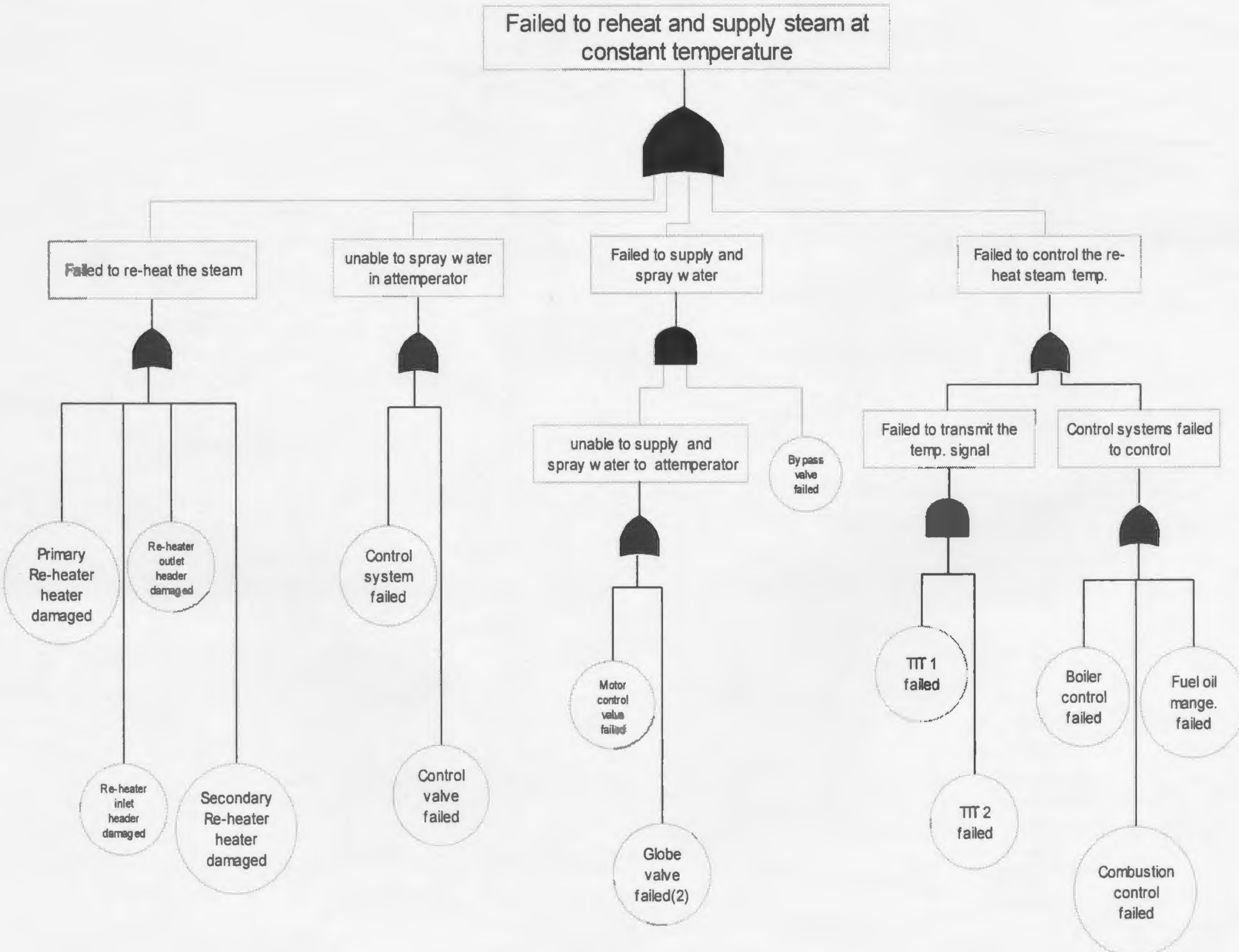
5.1.4 Steam generator - Super heater



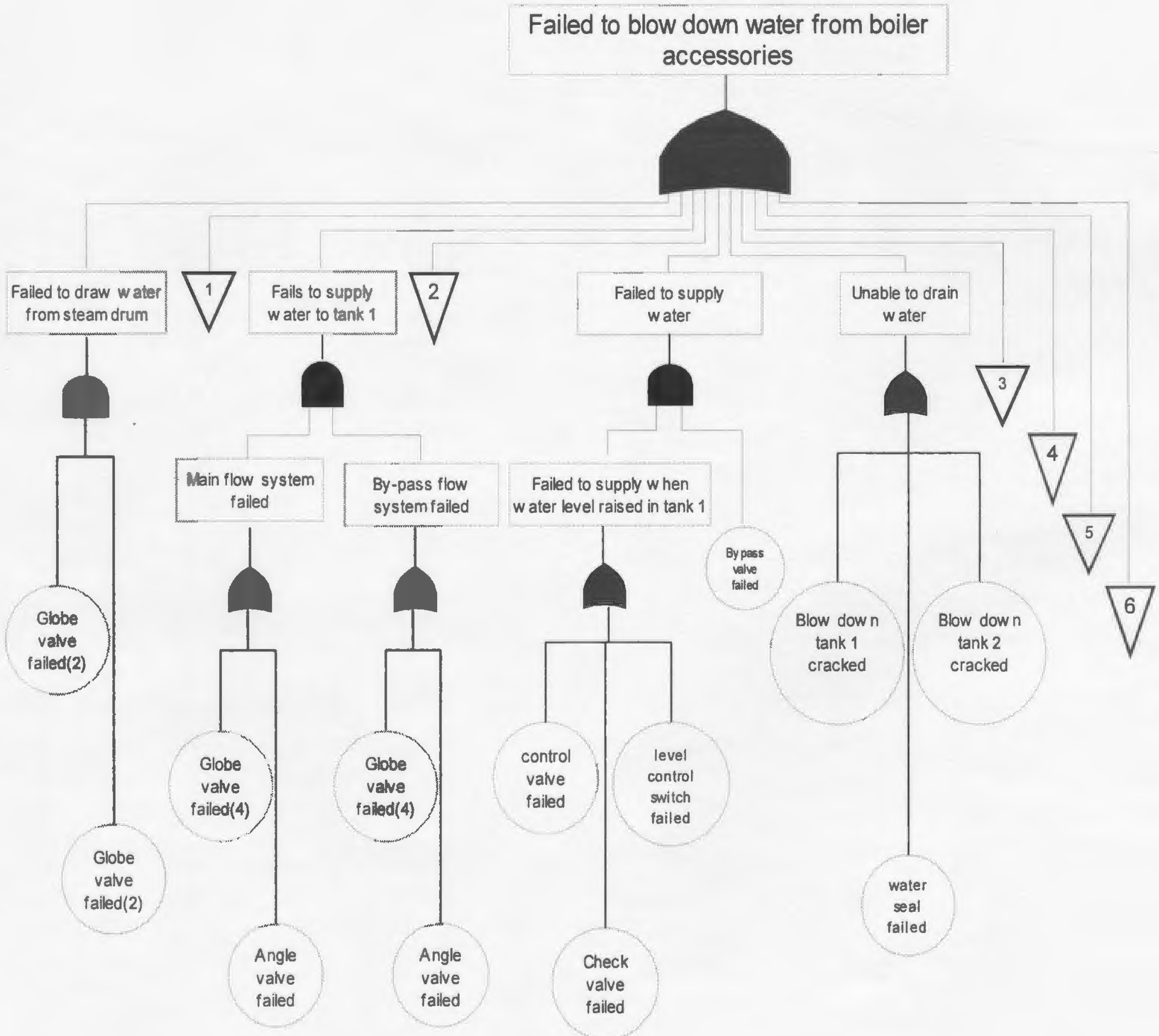
5.1.4 Steam generator - Super heater



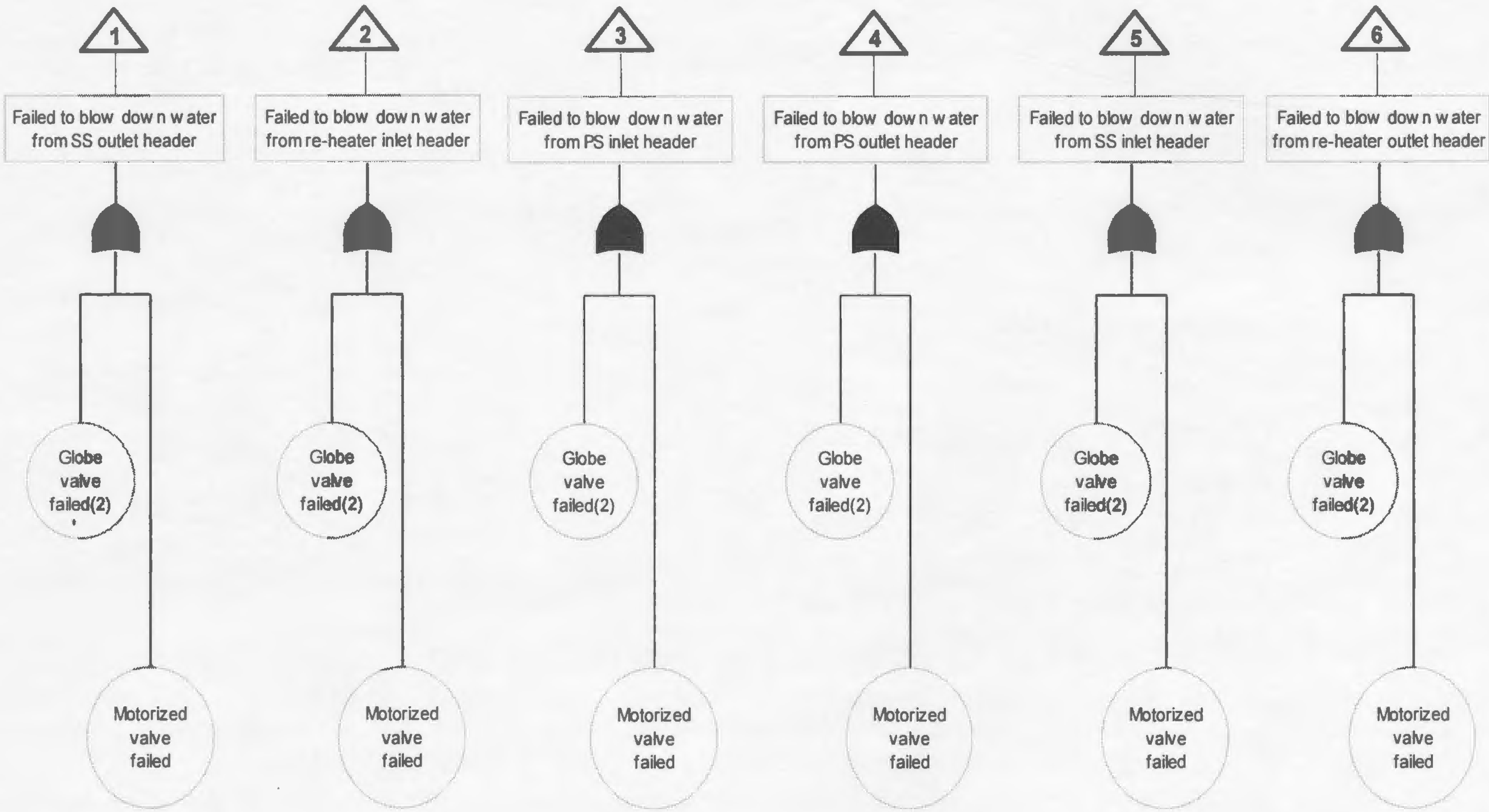
5.1.5 Steam generator - Re-heater



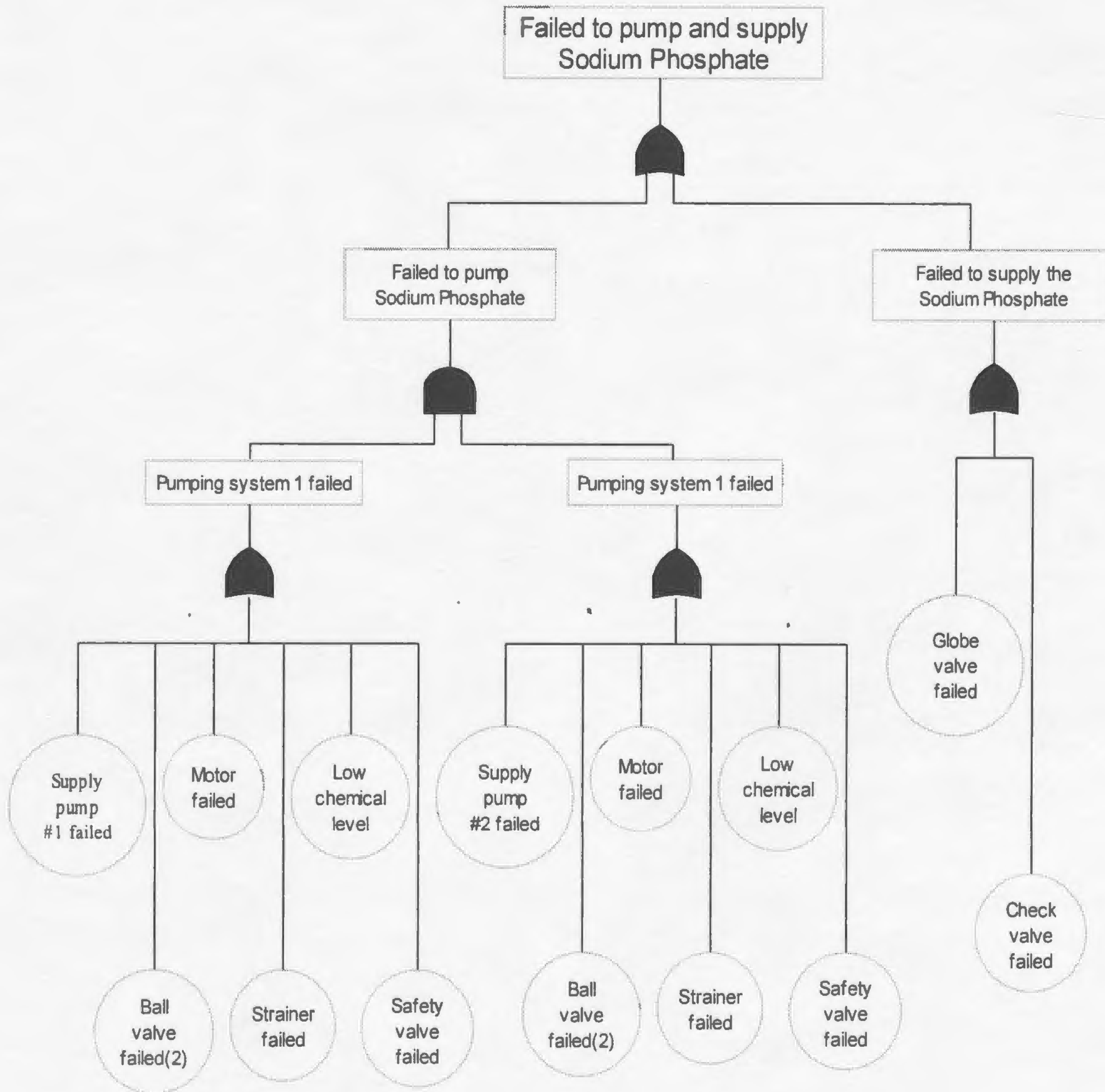
5.1.6 Steam generator- Blow down system



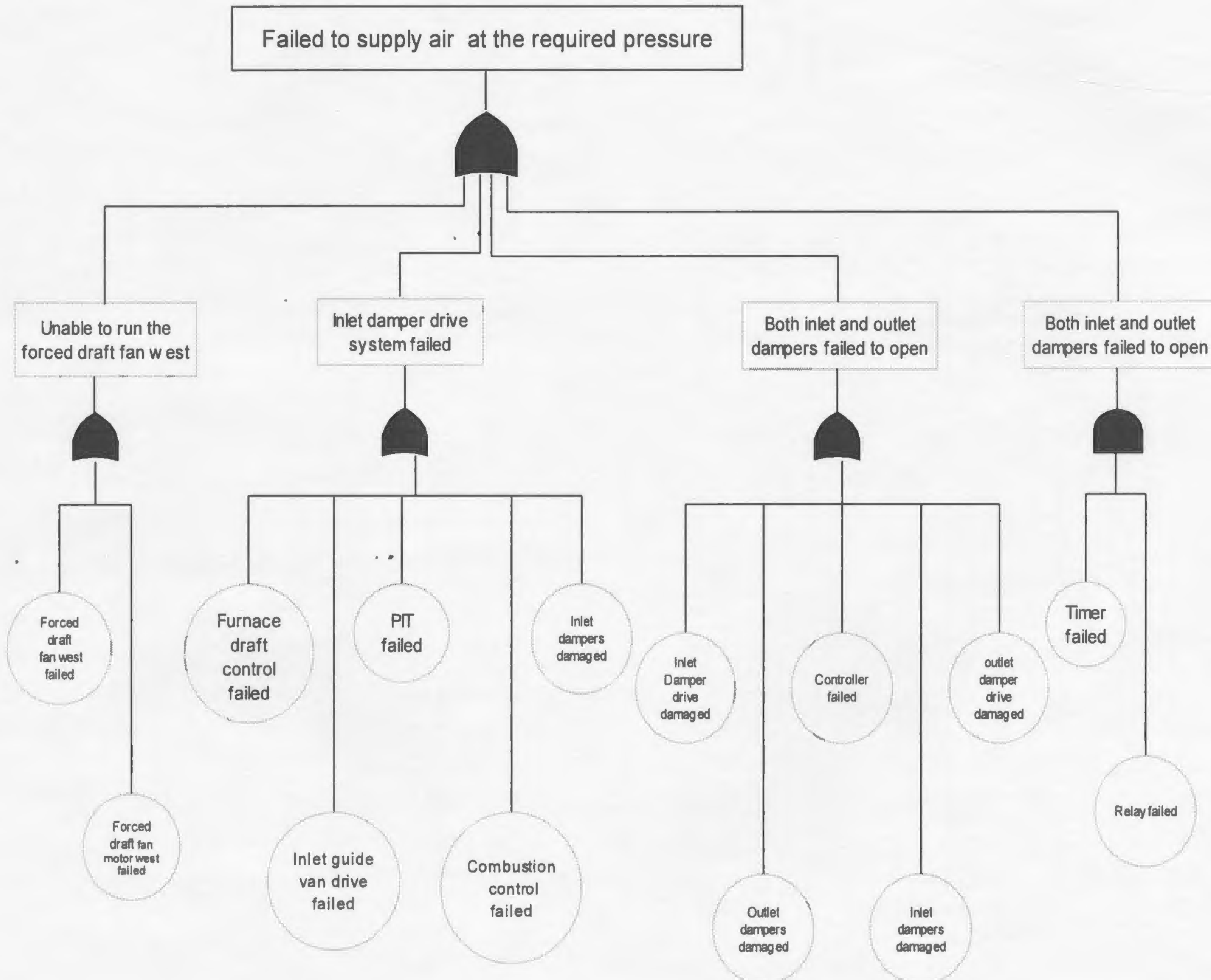
5.1.6 Steam generator- Blow down system



5.1.8 Steam generator-chemical supply system



5.2.1 (a) Forced draft fan west



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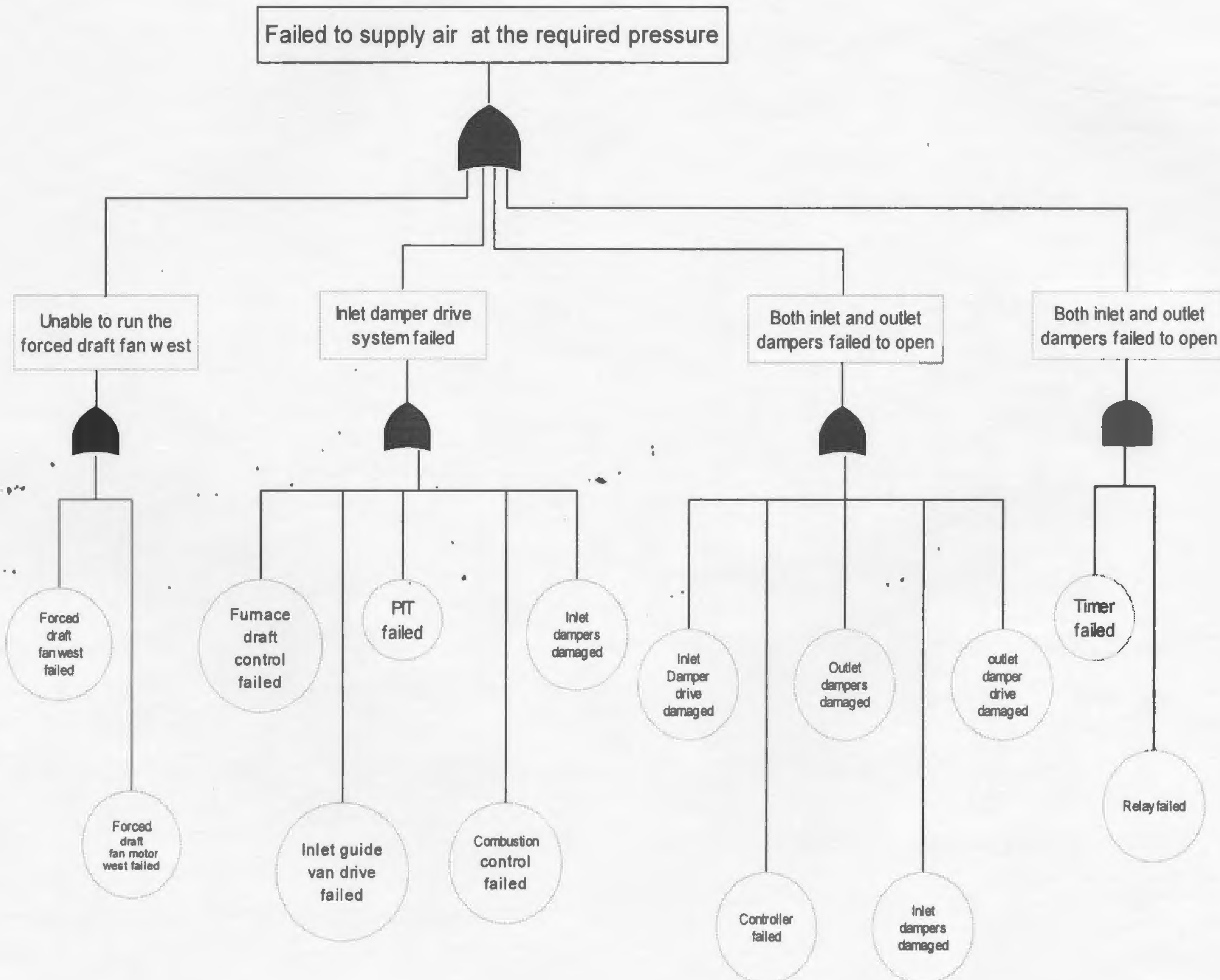
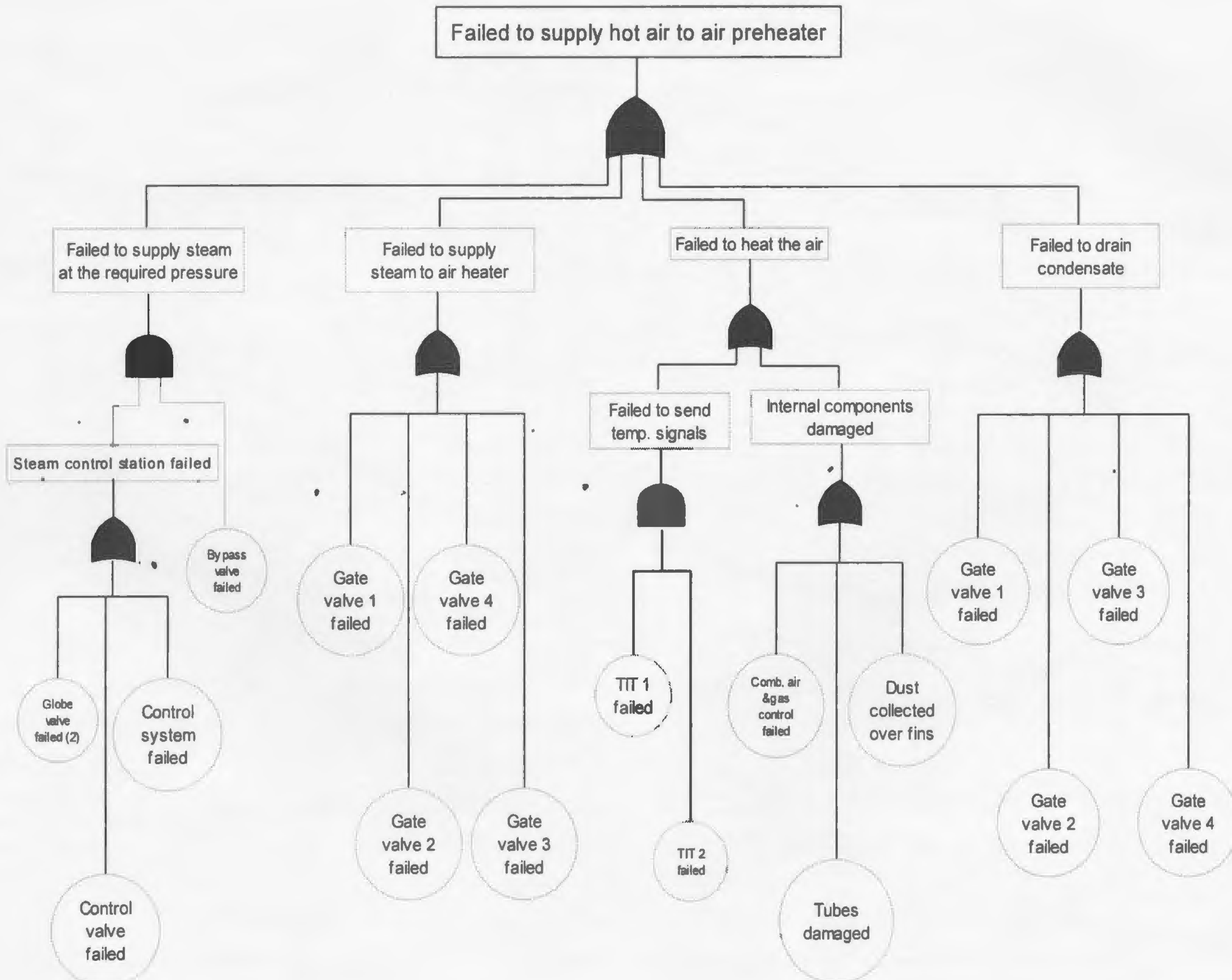
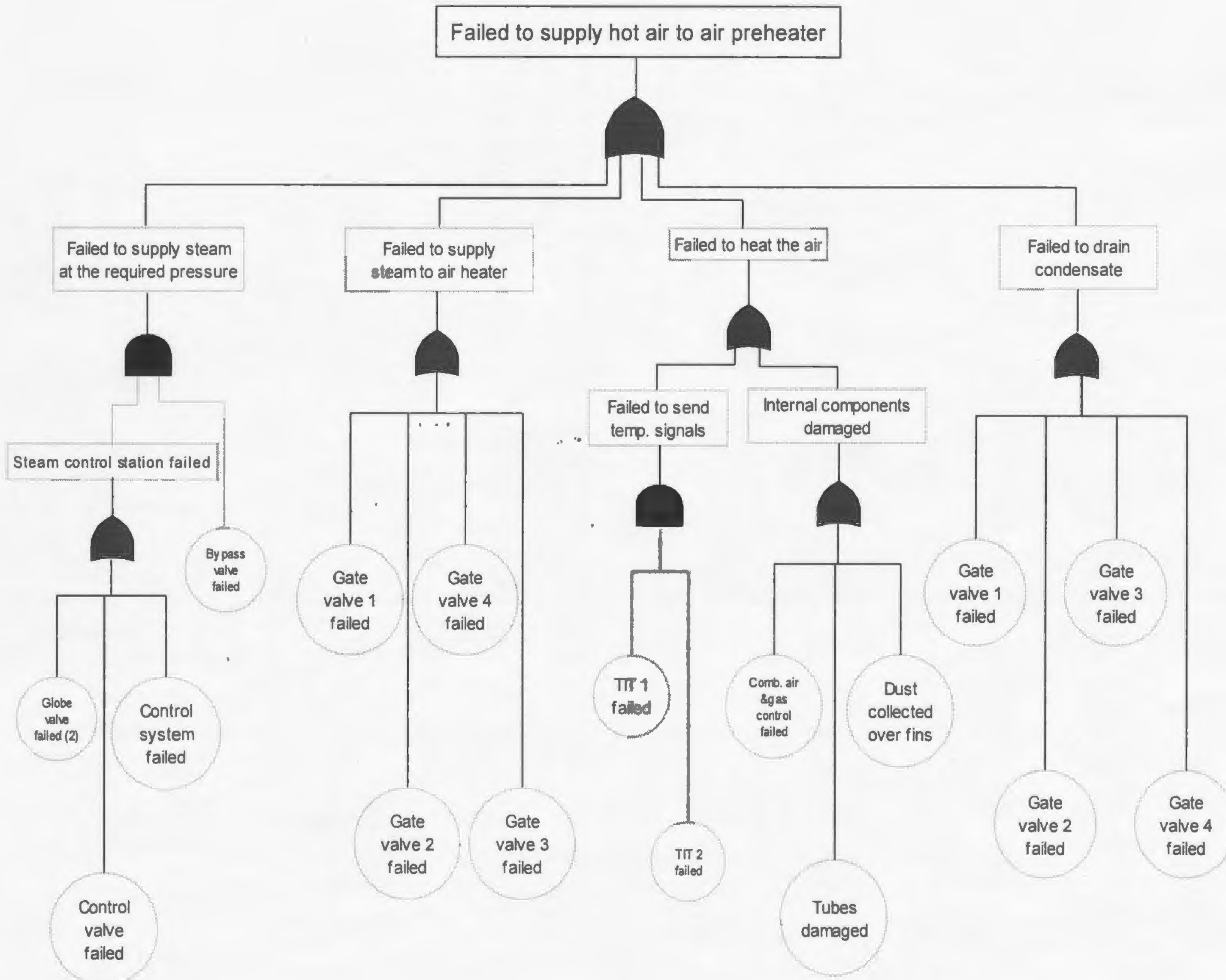
5.2.1 (b) Forced draft fan east



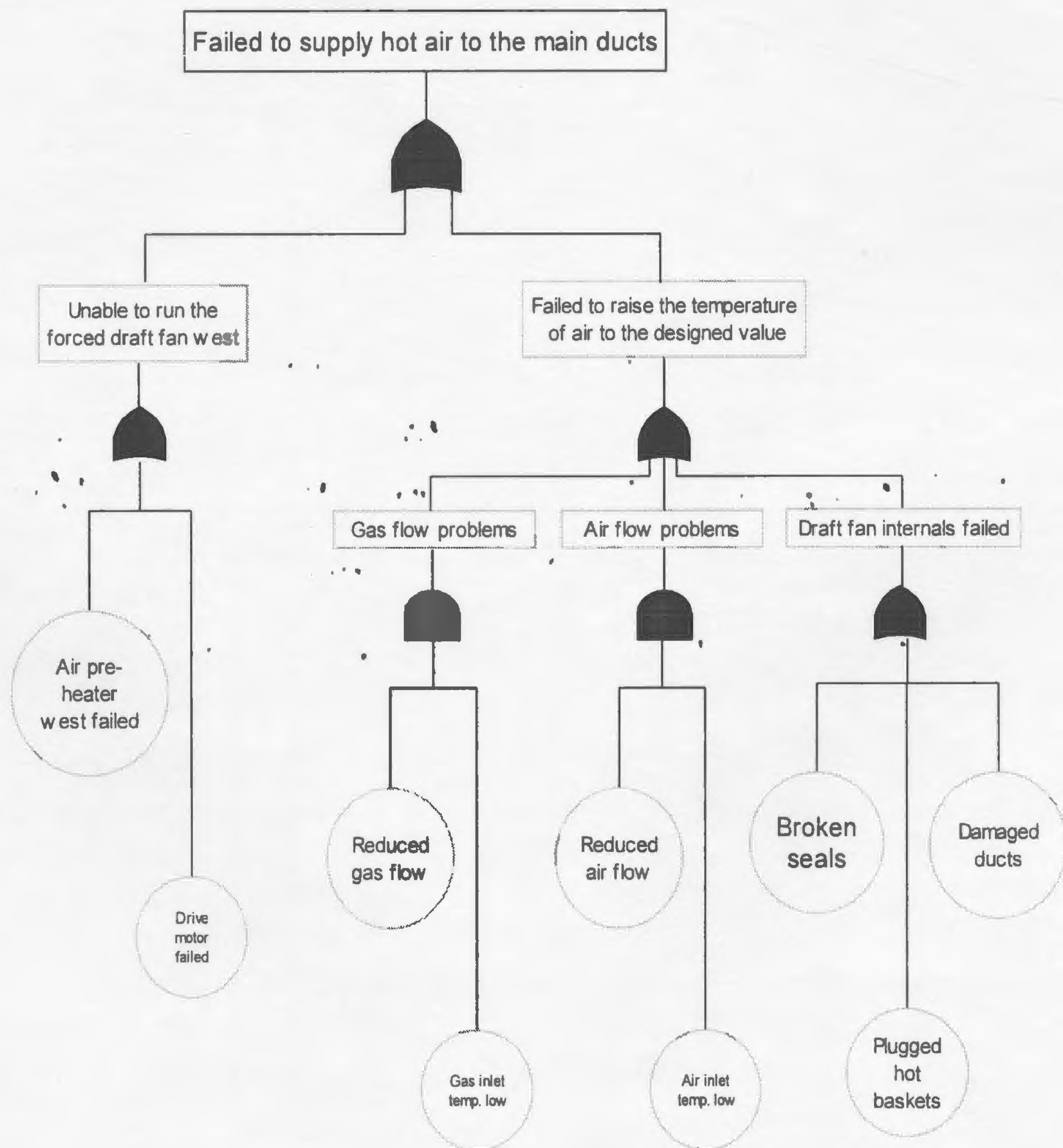
5.2.2 (a) Steam air heater west



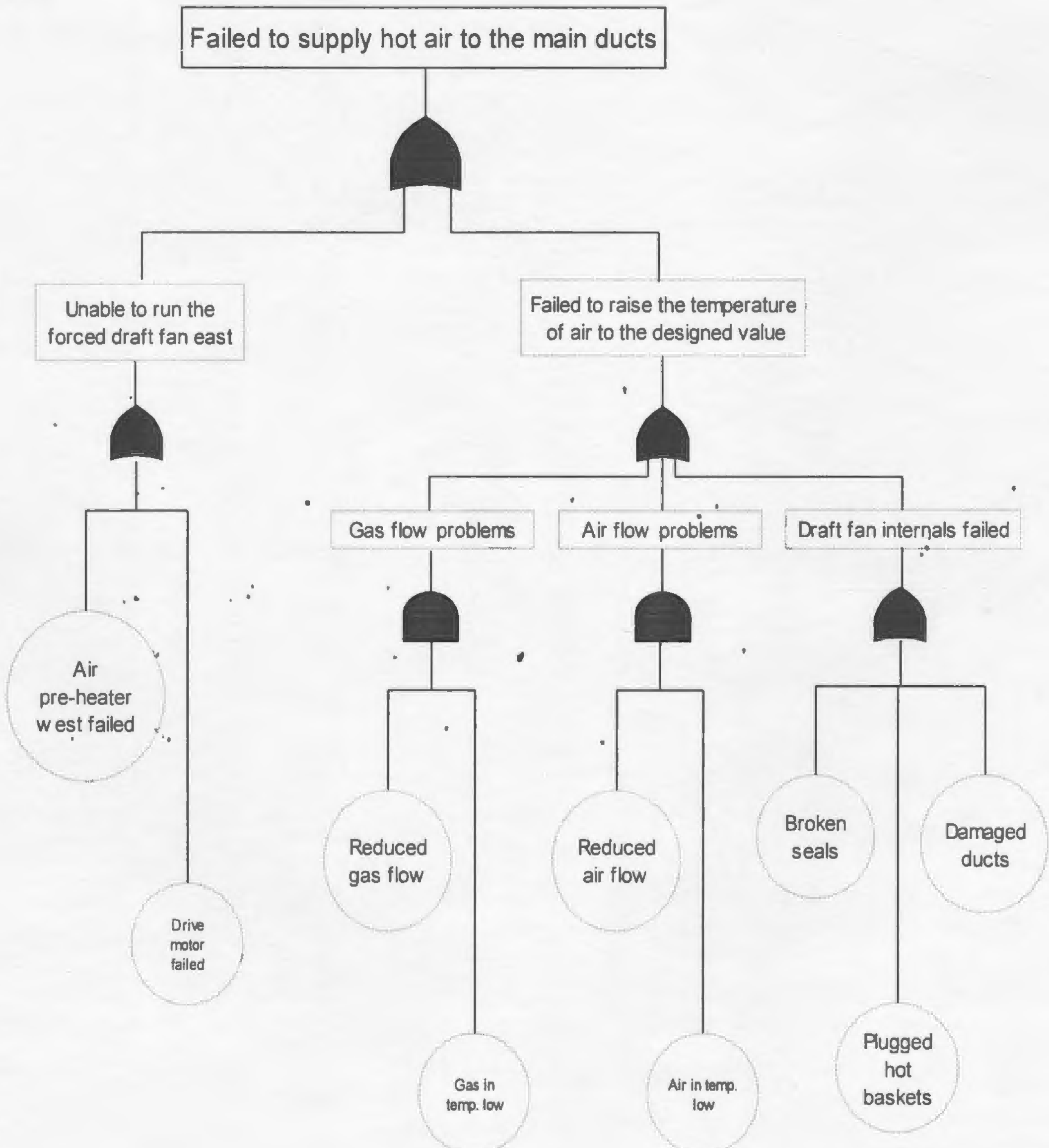
5.2.2 (b) Steam air heater east



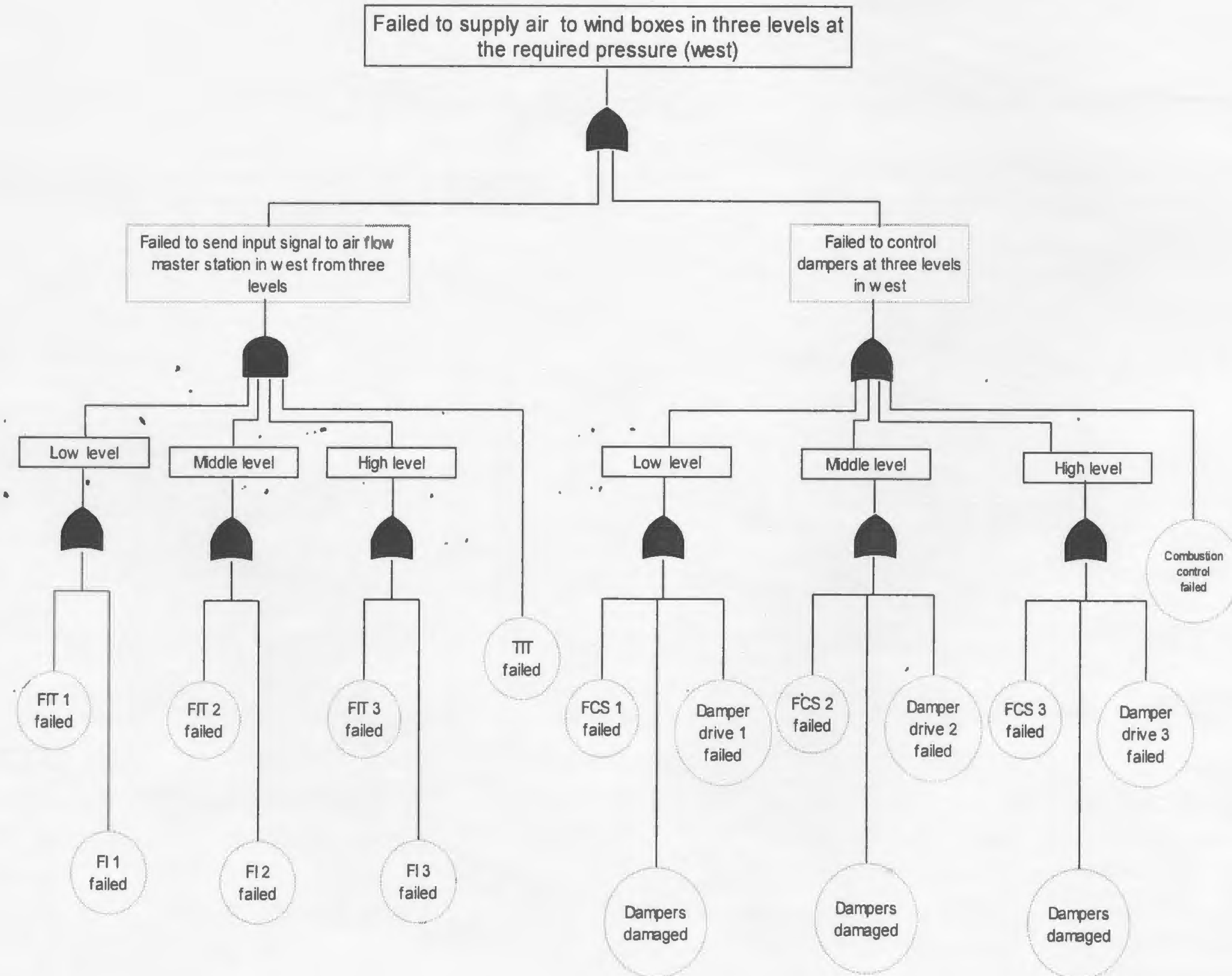
5.2.3 (a) Air pre heater west



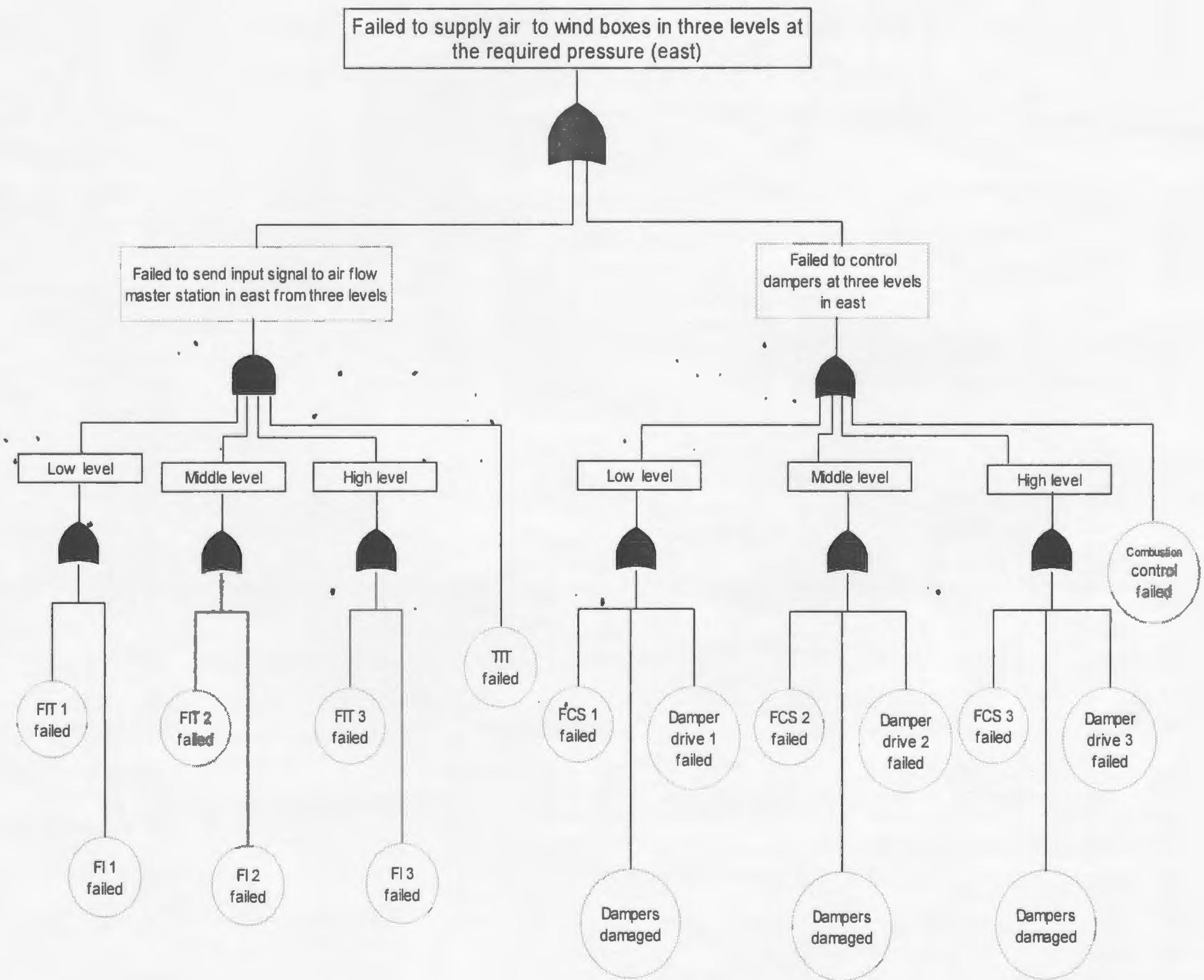
5.2.3 (b) Air pre heater east



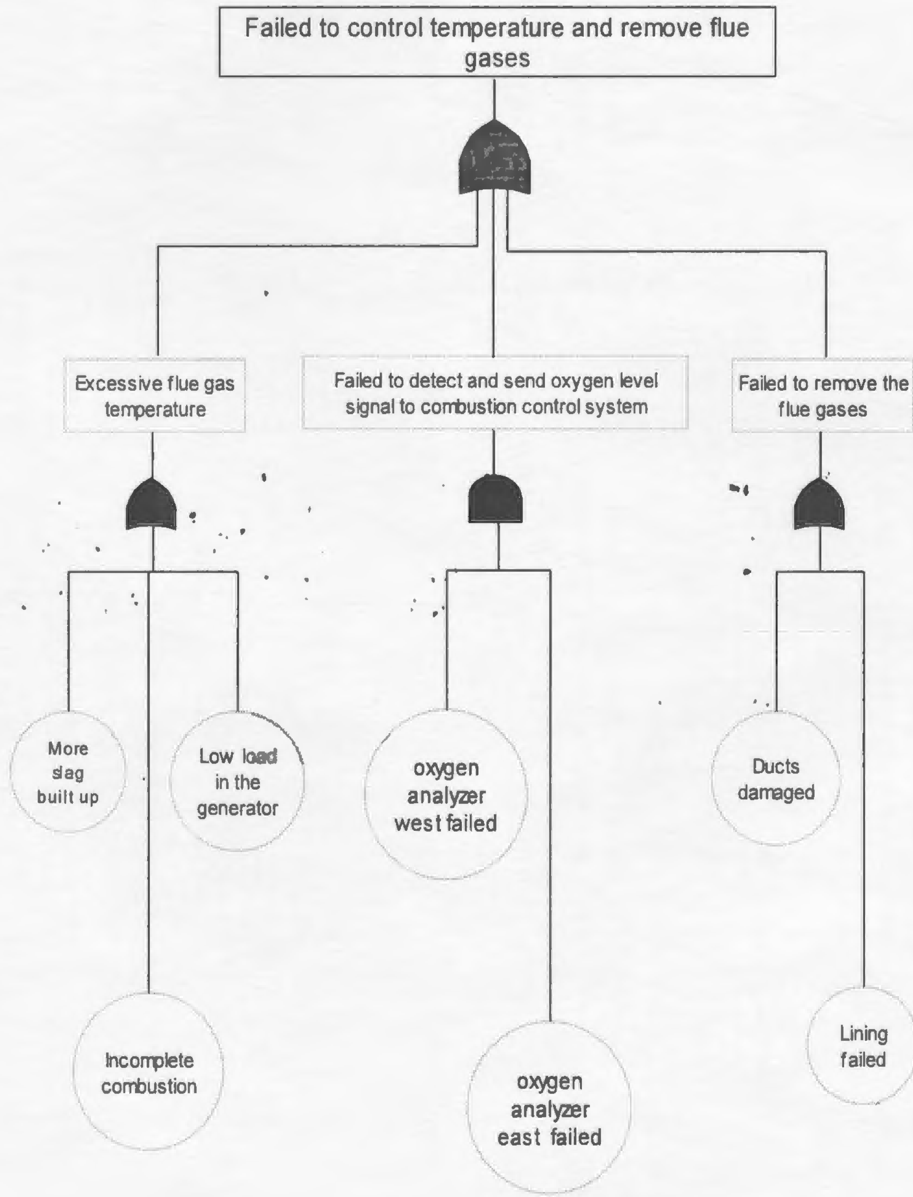
5.2.4 (a) Air flow control system west



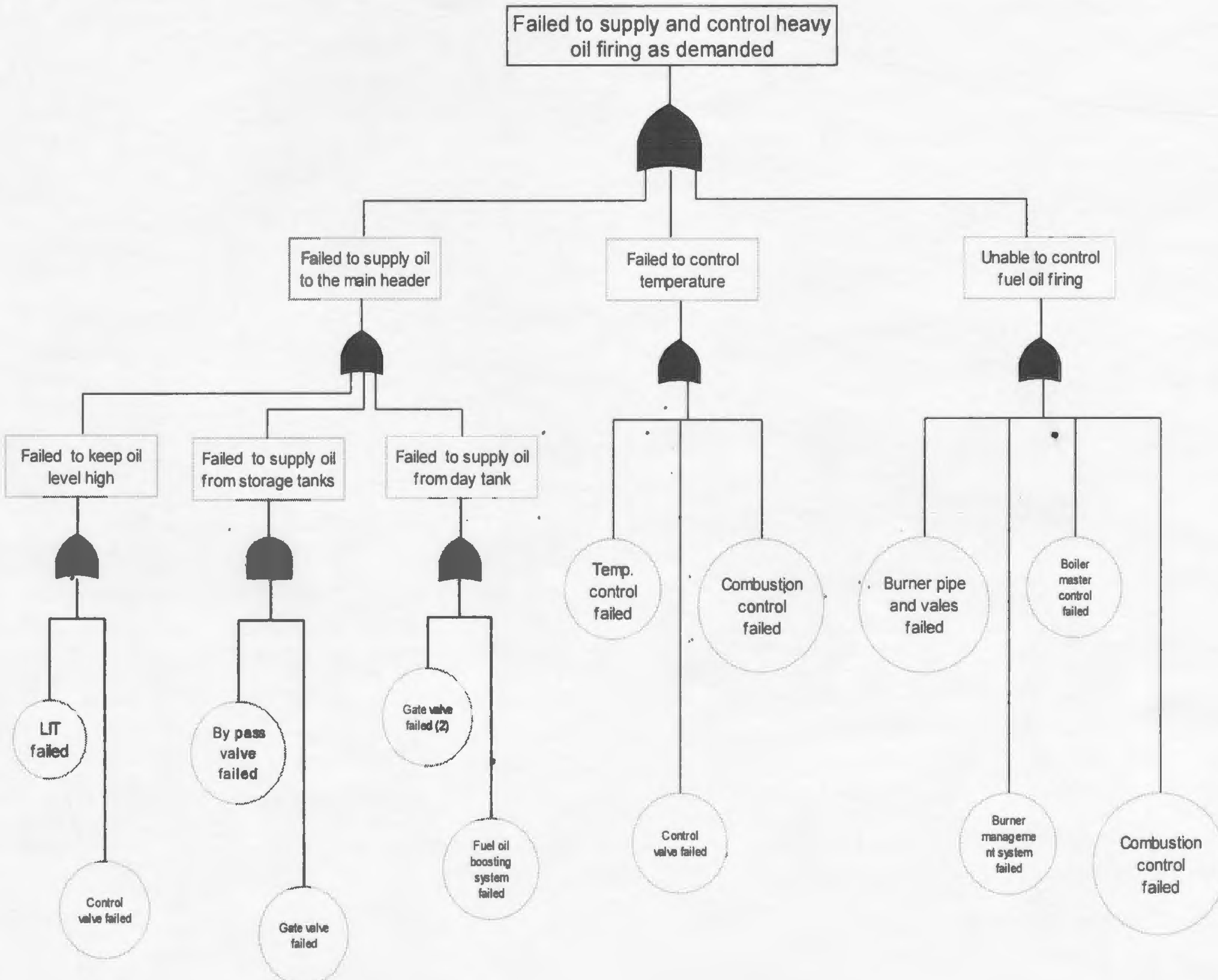
5.2.4 (b) Air flow control system east



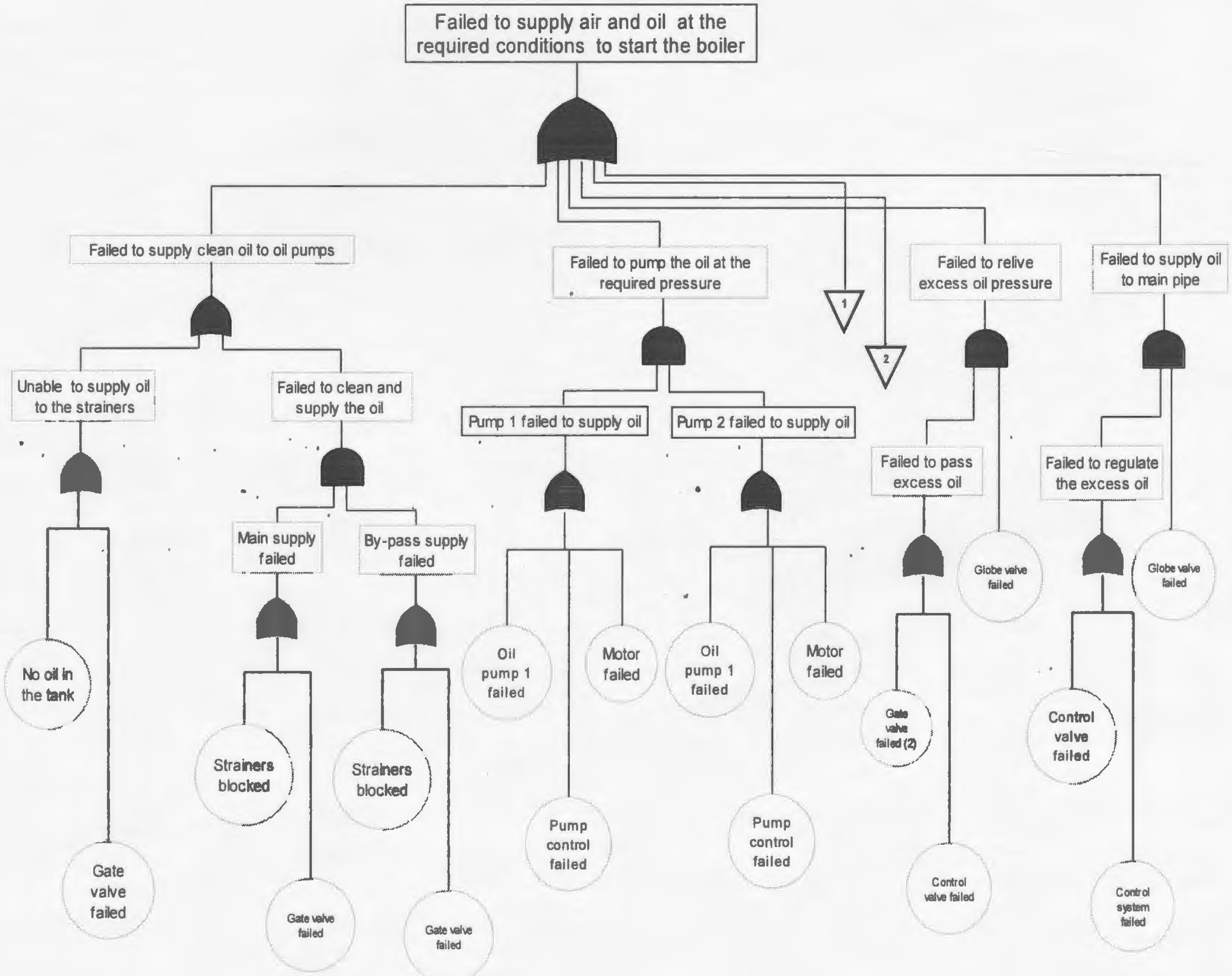
5.2.5 Flue gas system



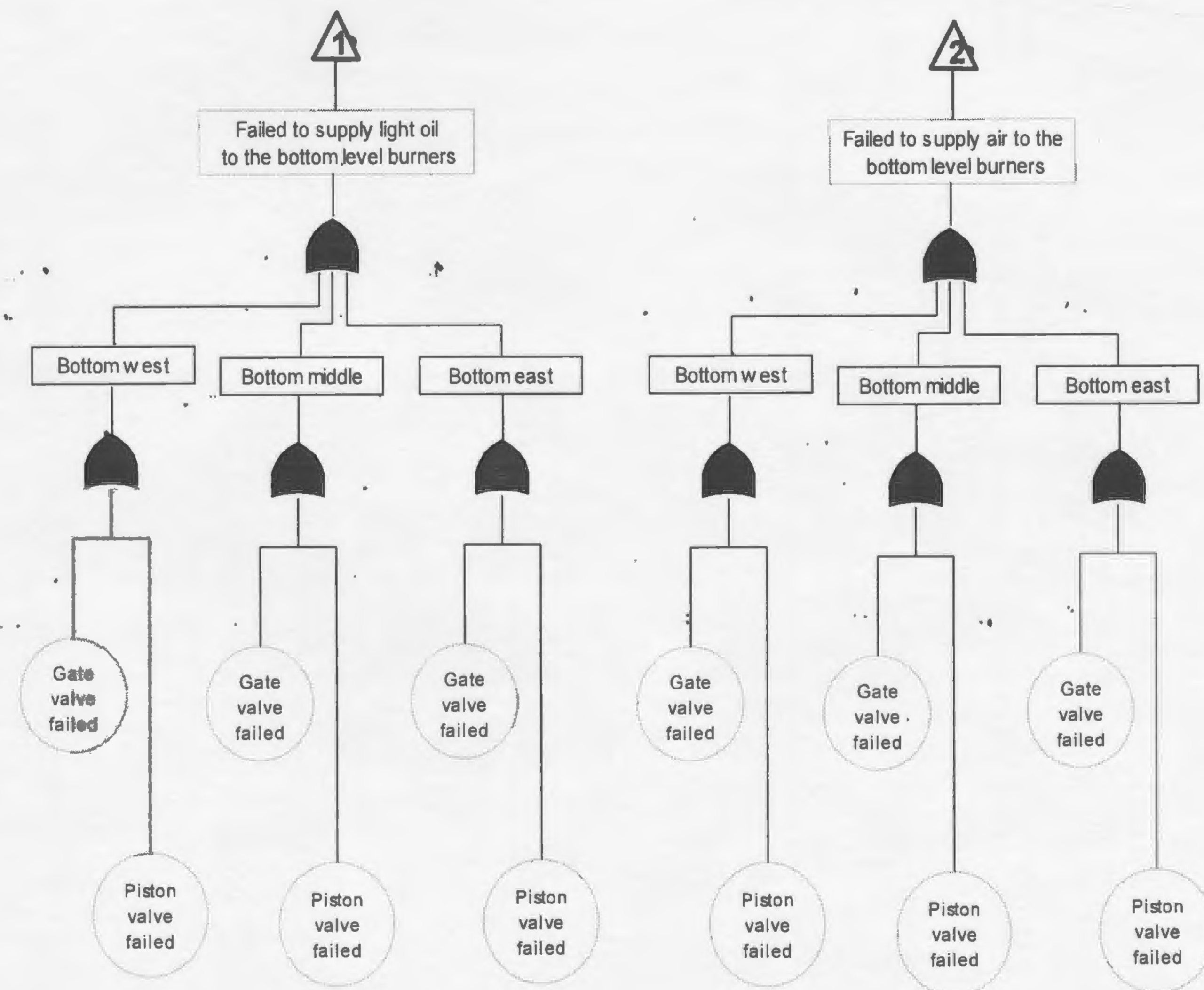
5.3.1 Heavy oil system



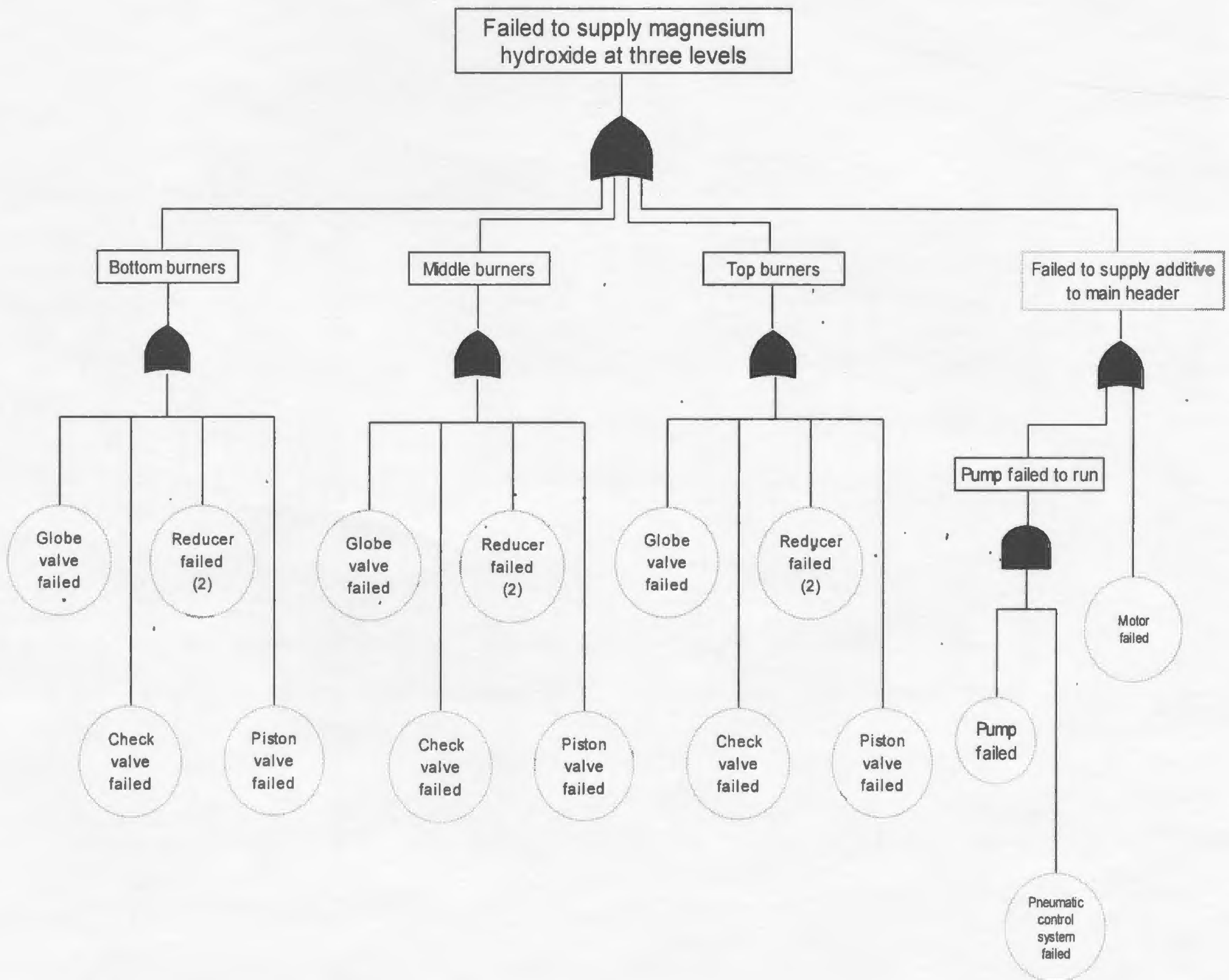
5.3.2 Light oil system



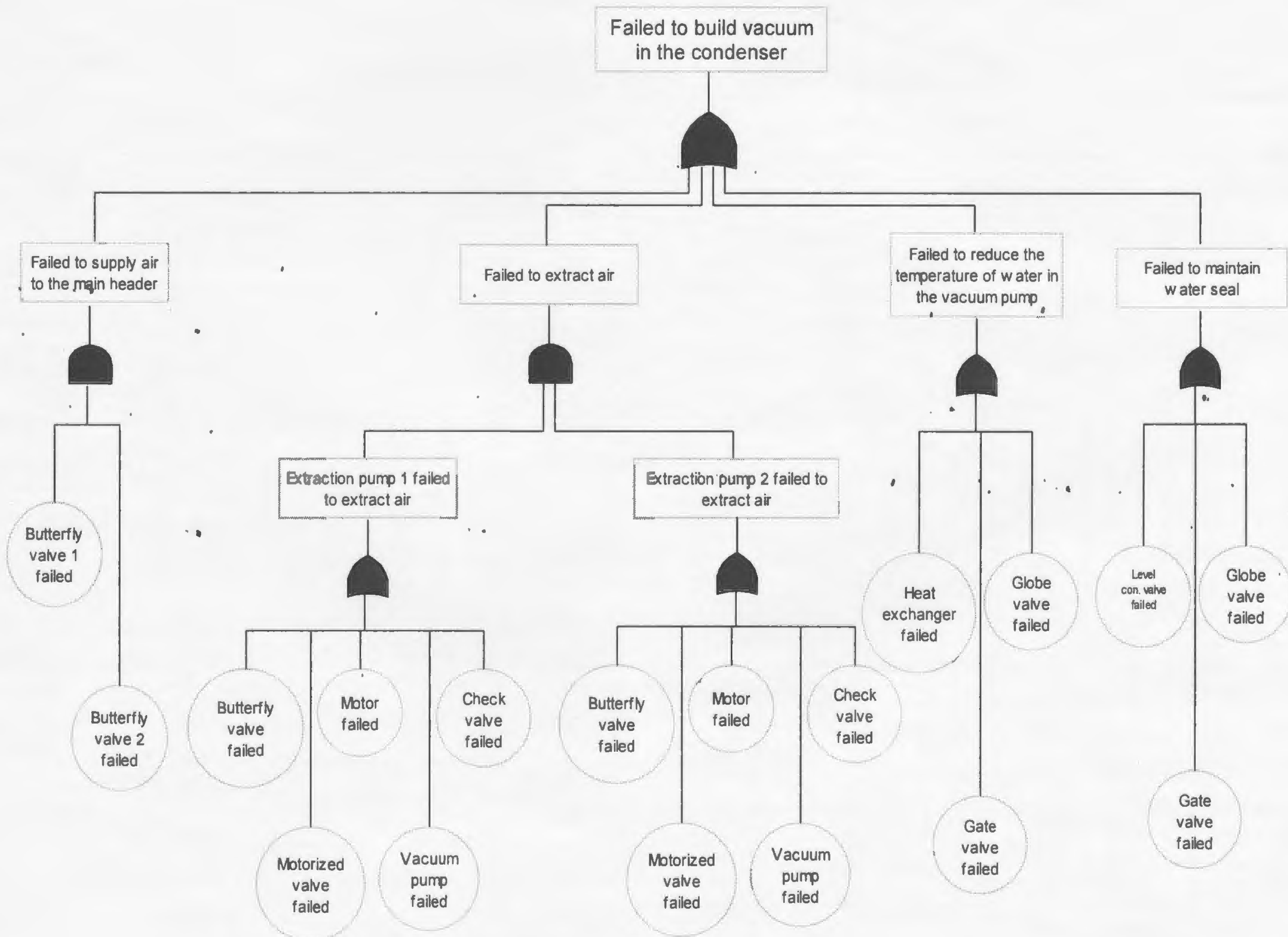
5.3.2 Light oil system



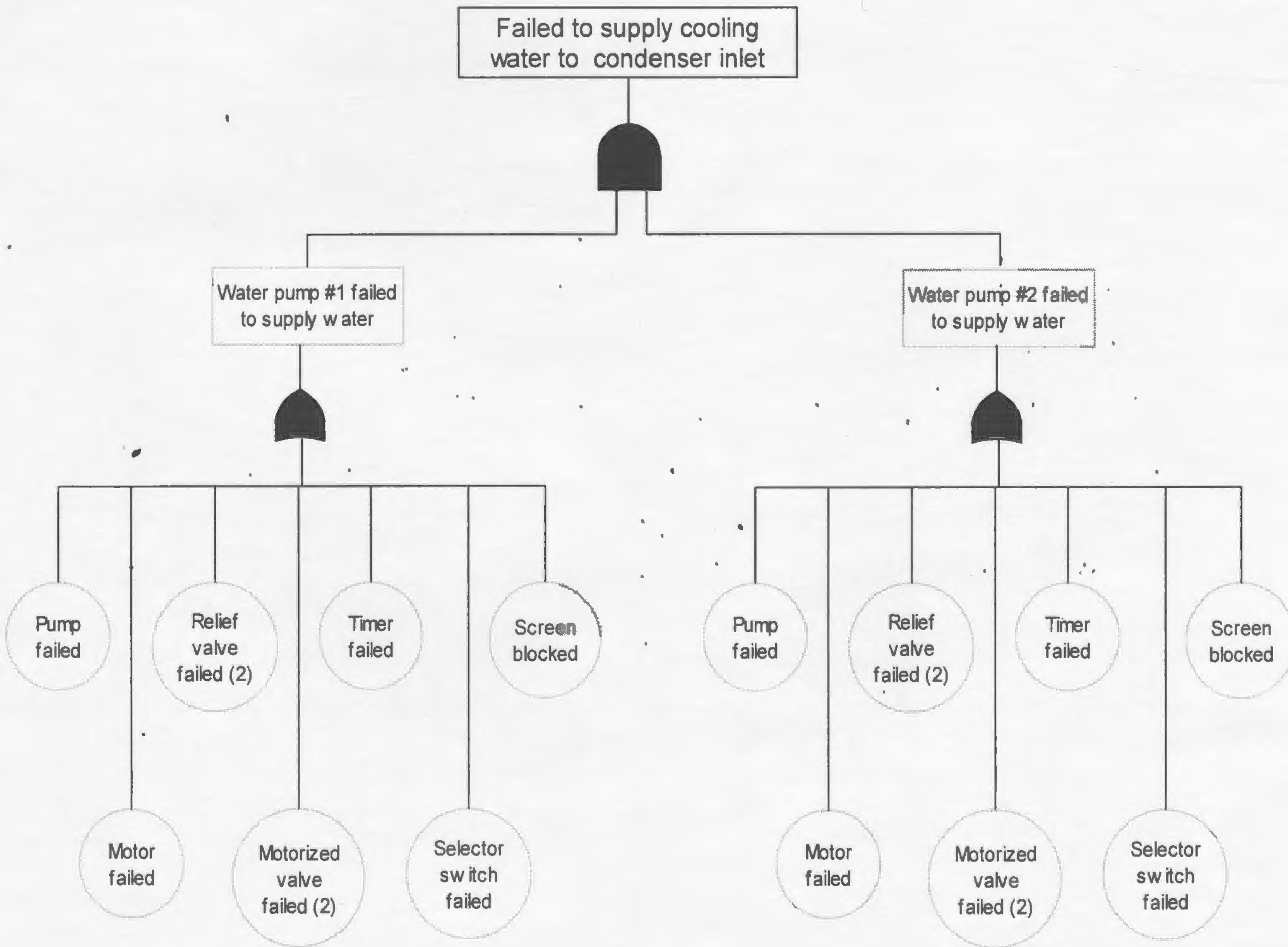
5.3.3 Fuel additive system



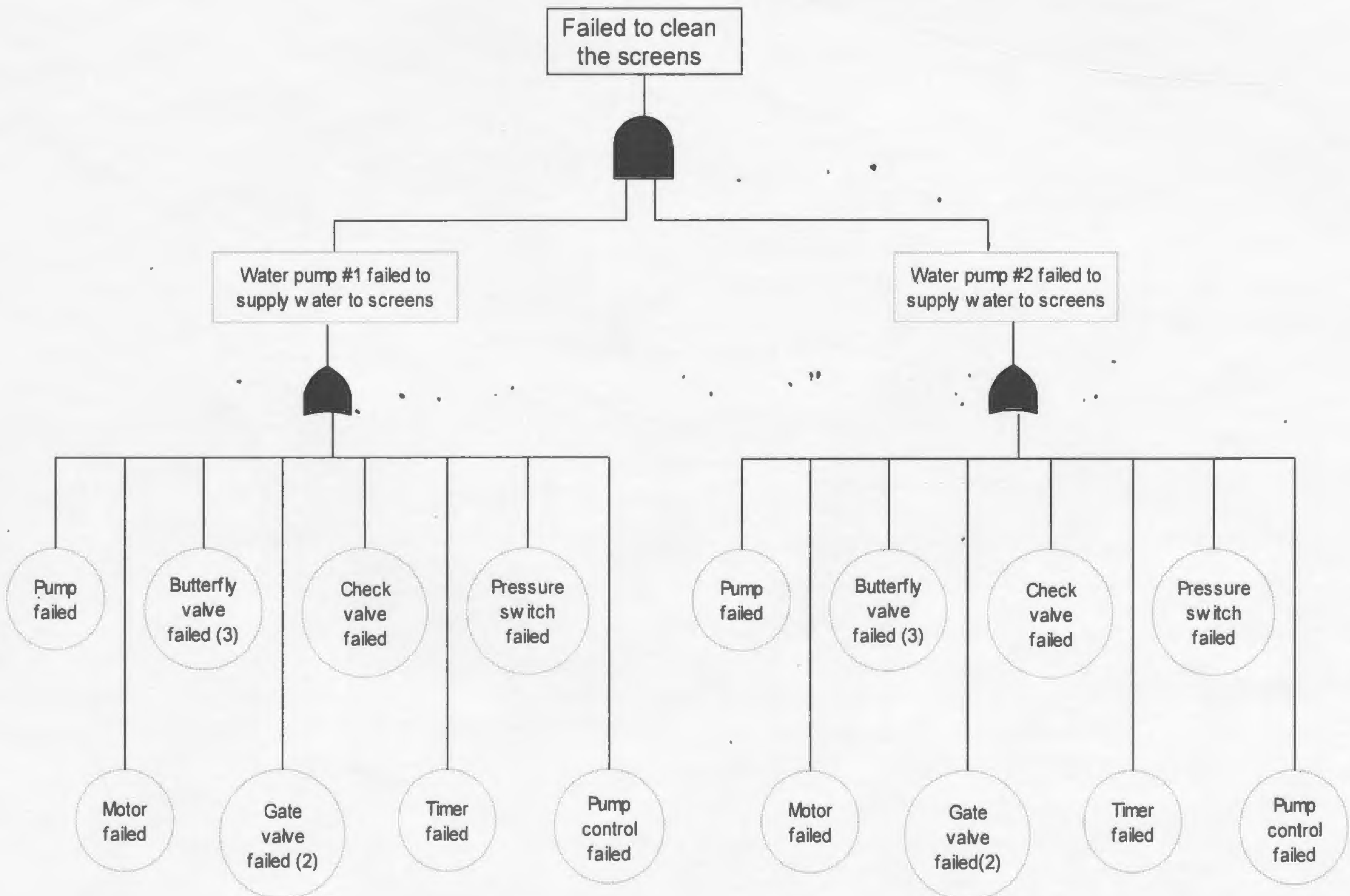
5.6.3 Condenser



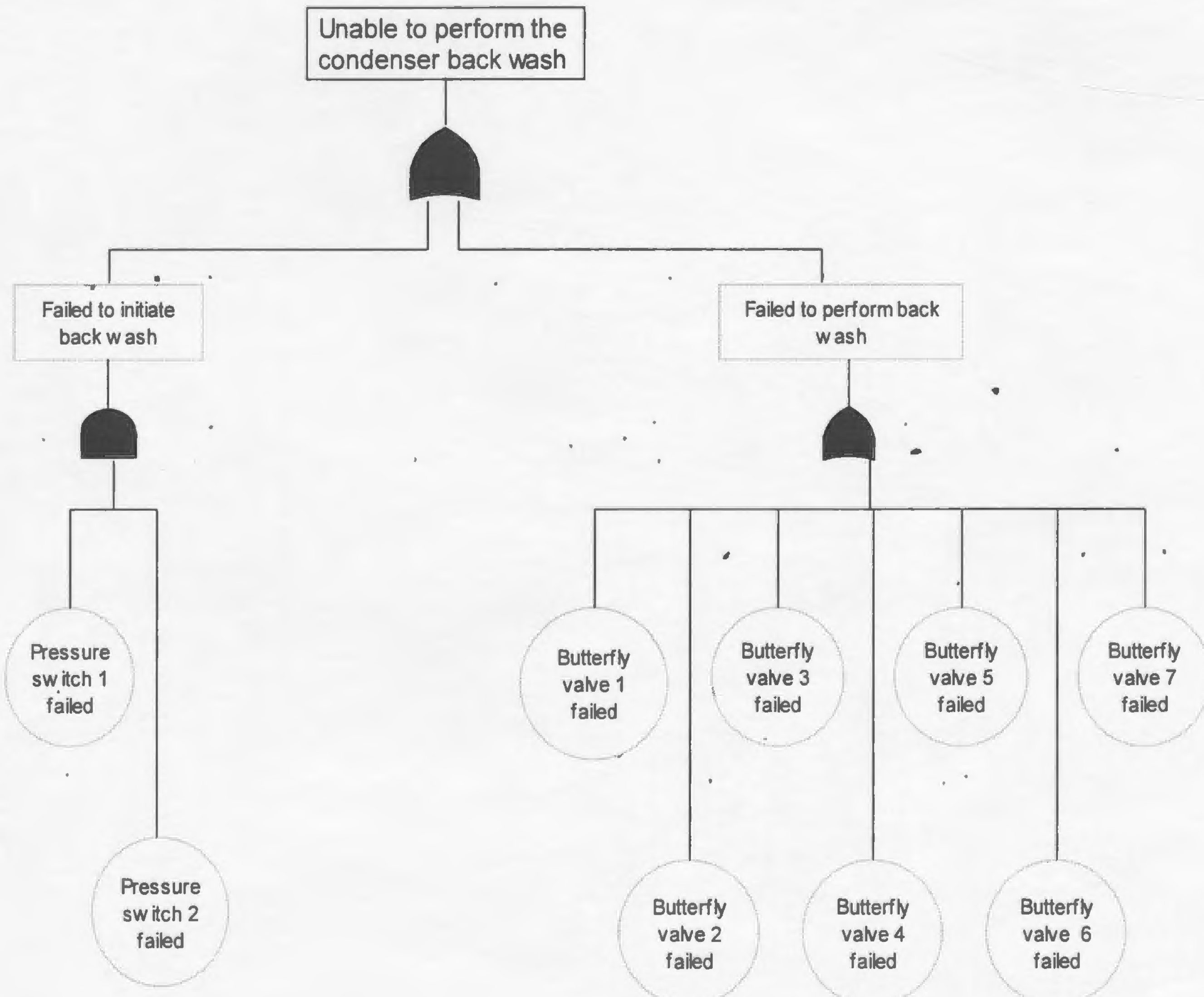
5.6.1 (a) Condenser



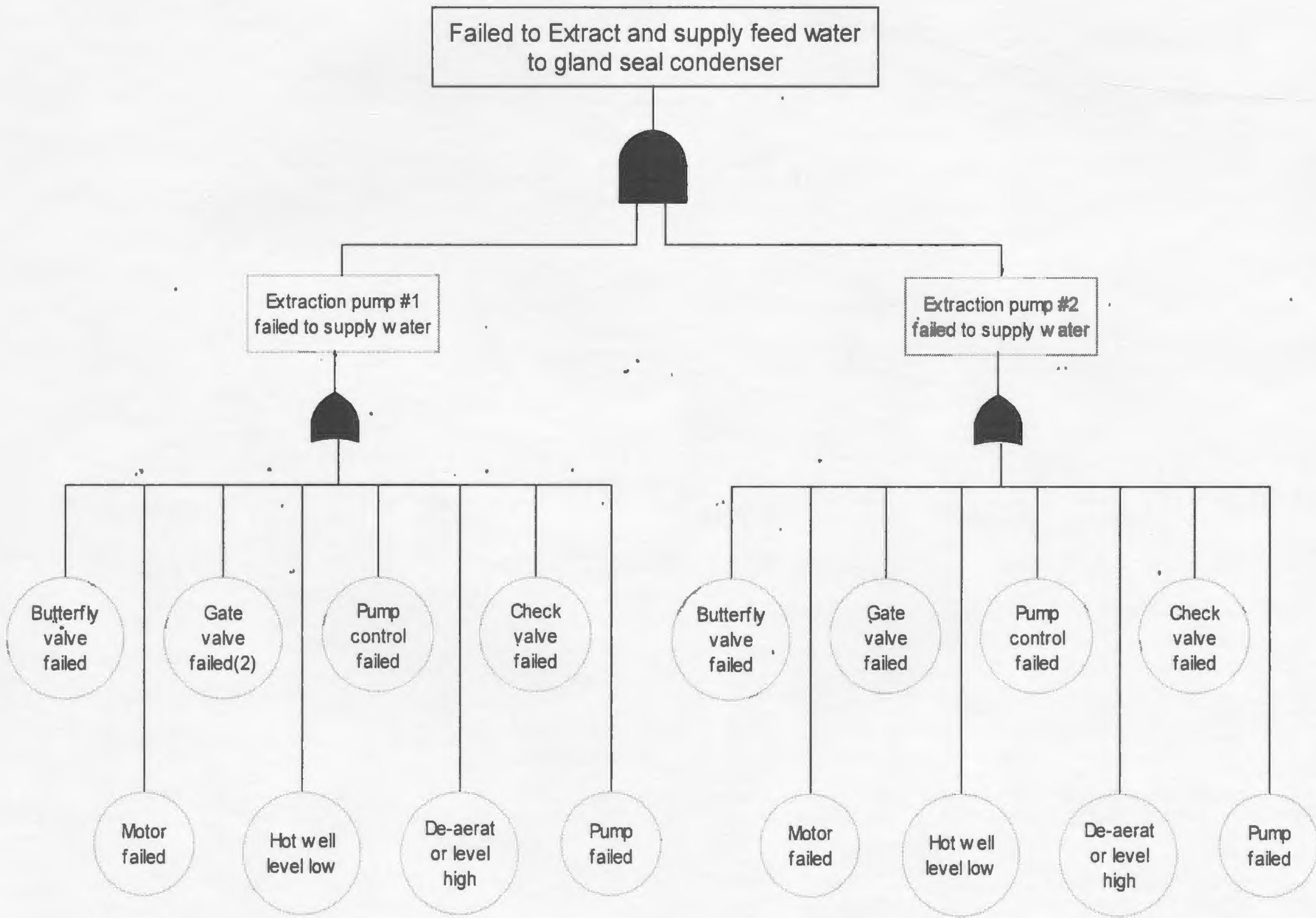
5.6.1 (b) Condenser



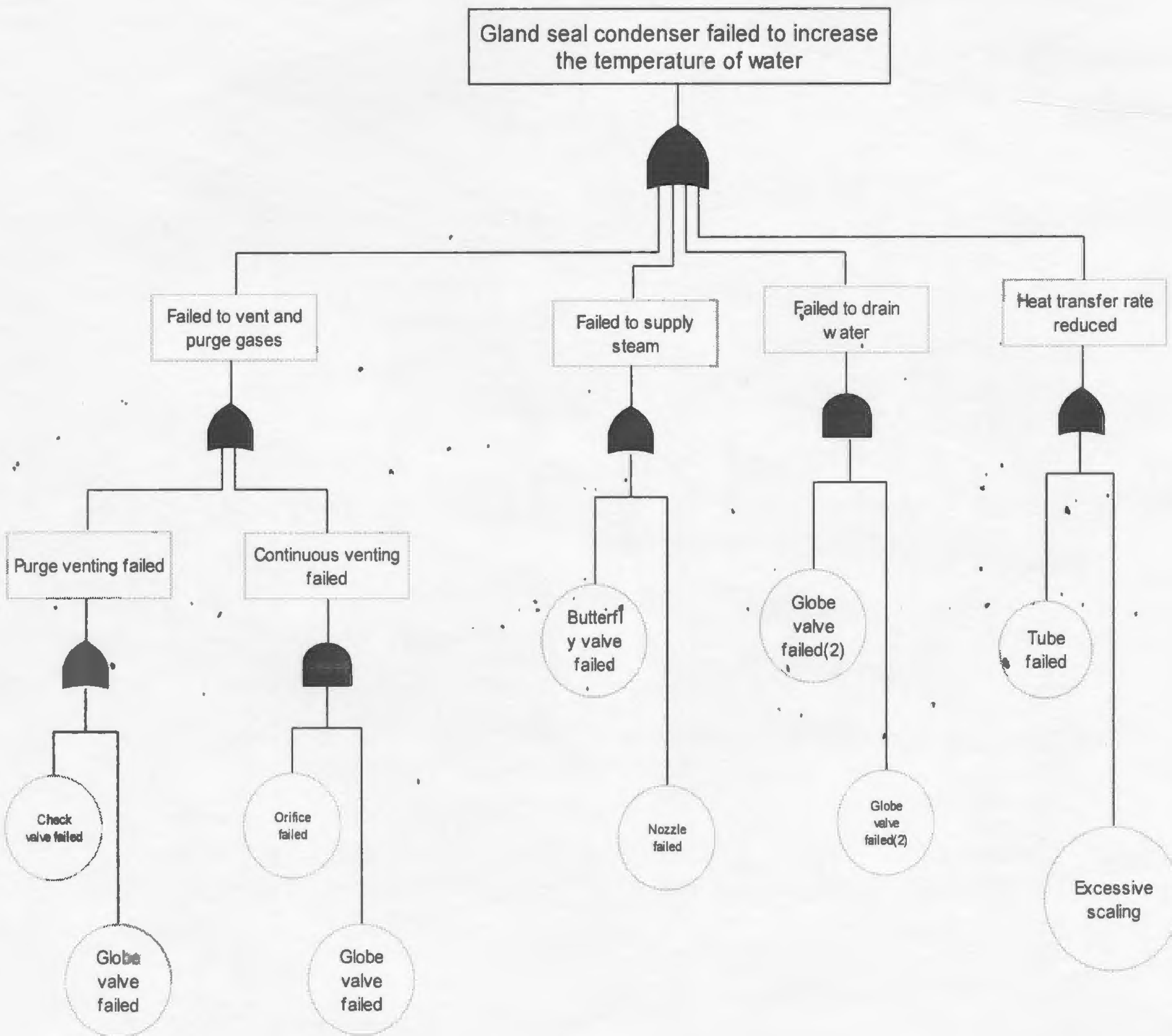
5.6.1 (c) Condenser



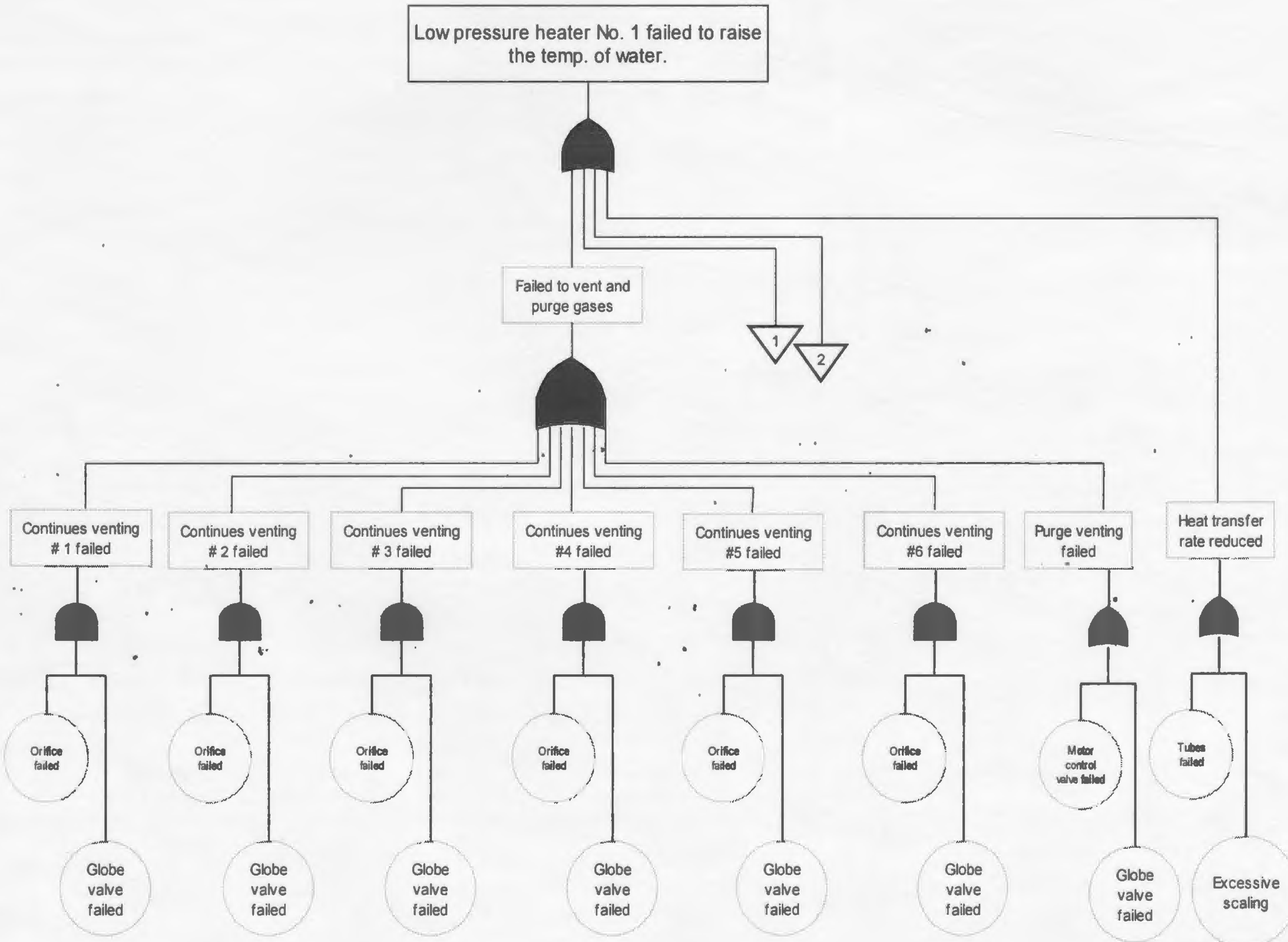
5.7.2 LP- Water extraction



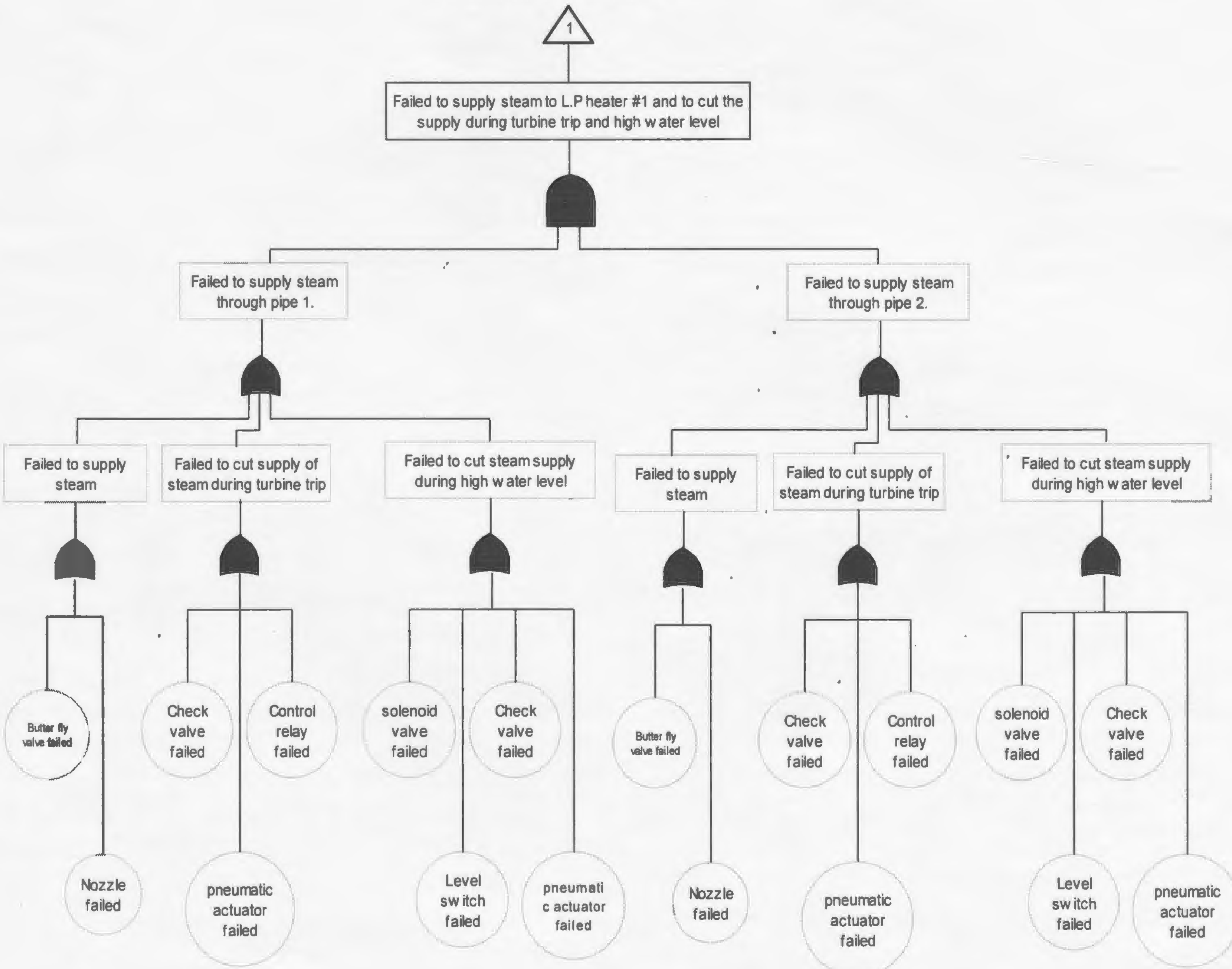
5.7.2 (a) LP- Gland seal condenser



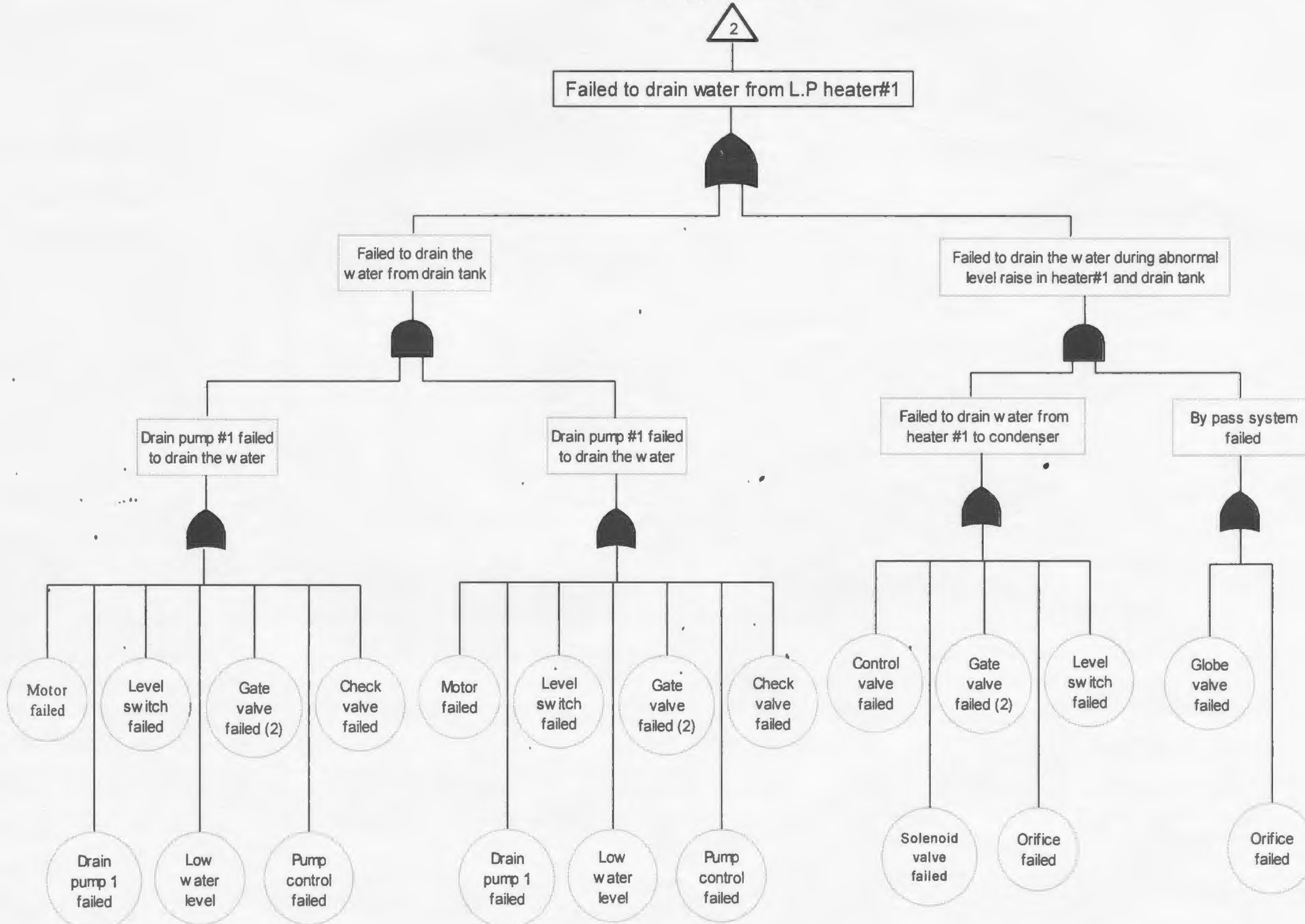
5.7.2 (b) LP heater #`1



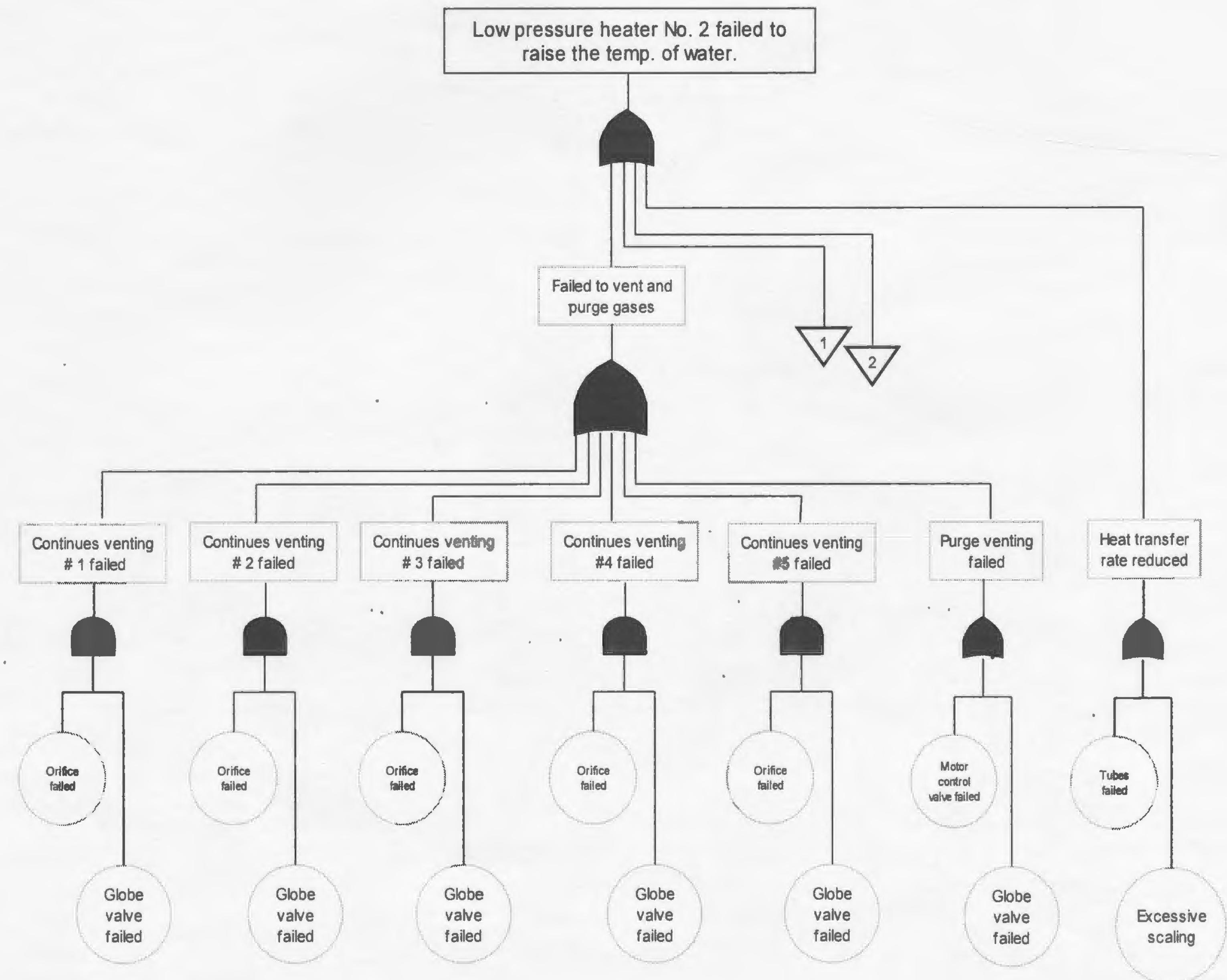
5.7.2 (b) LP heater #1



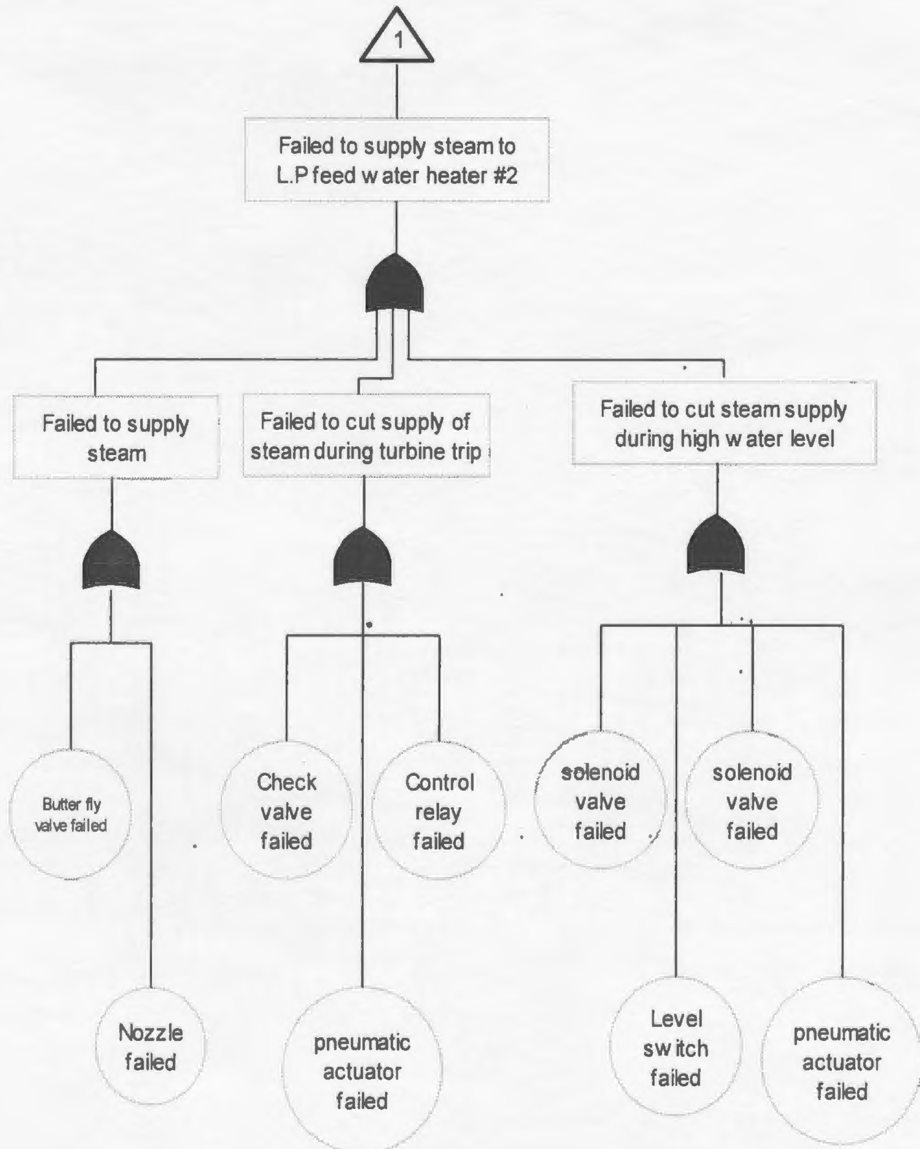
5.7.2 (b) LP heater #1



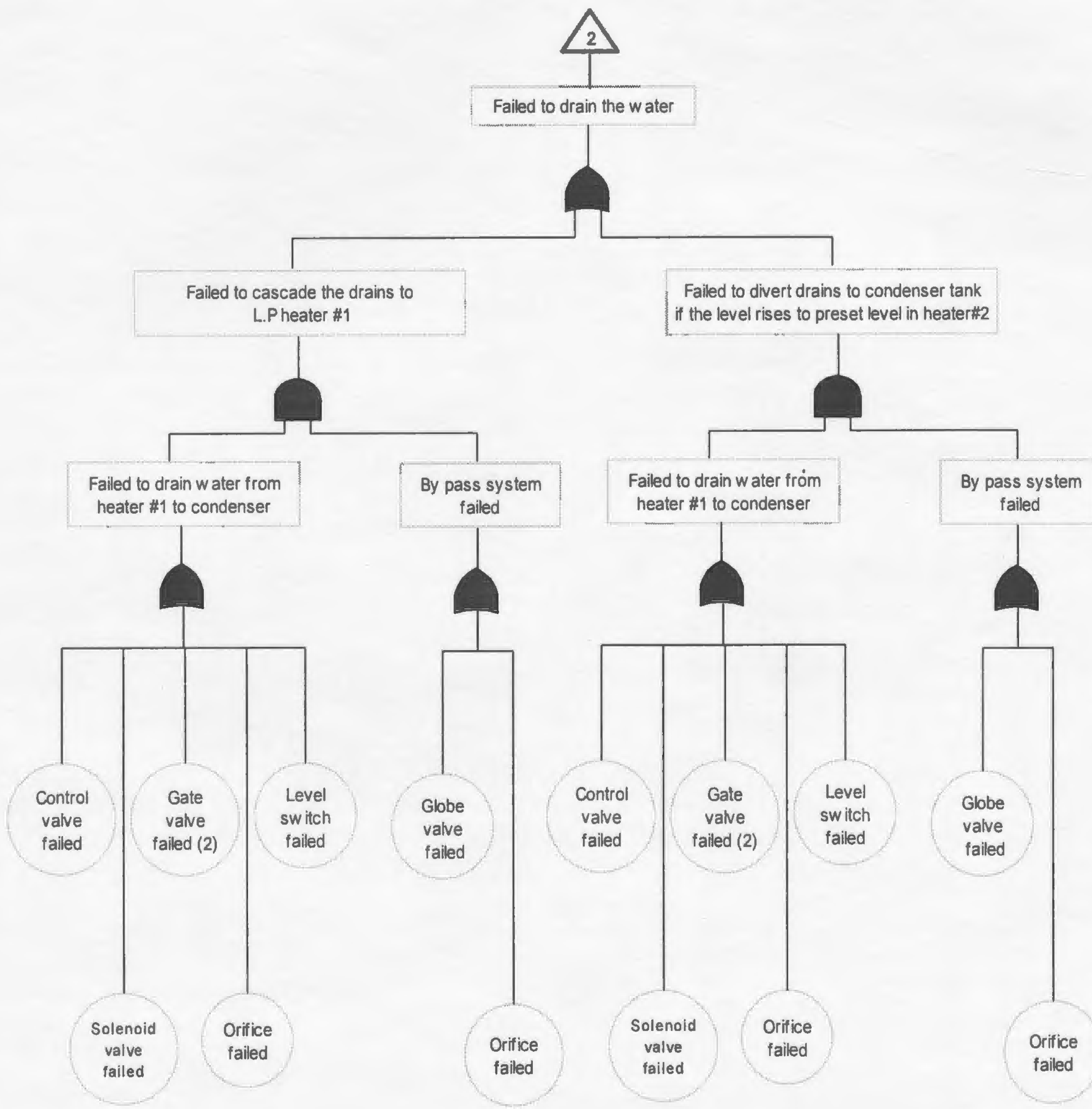
5.7.2 (c) LP Heater #2



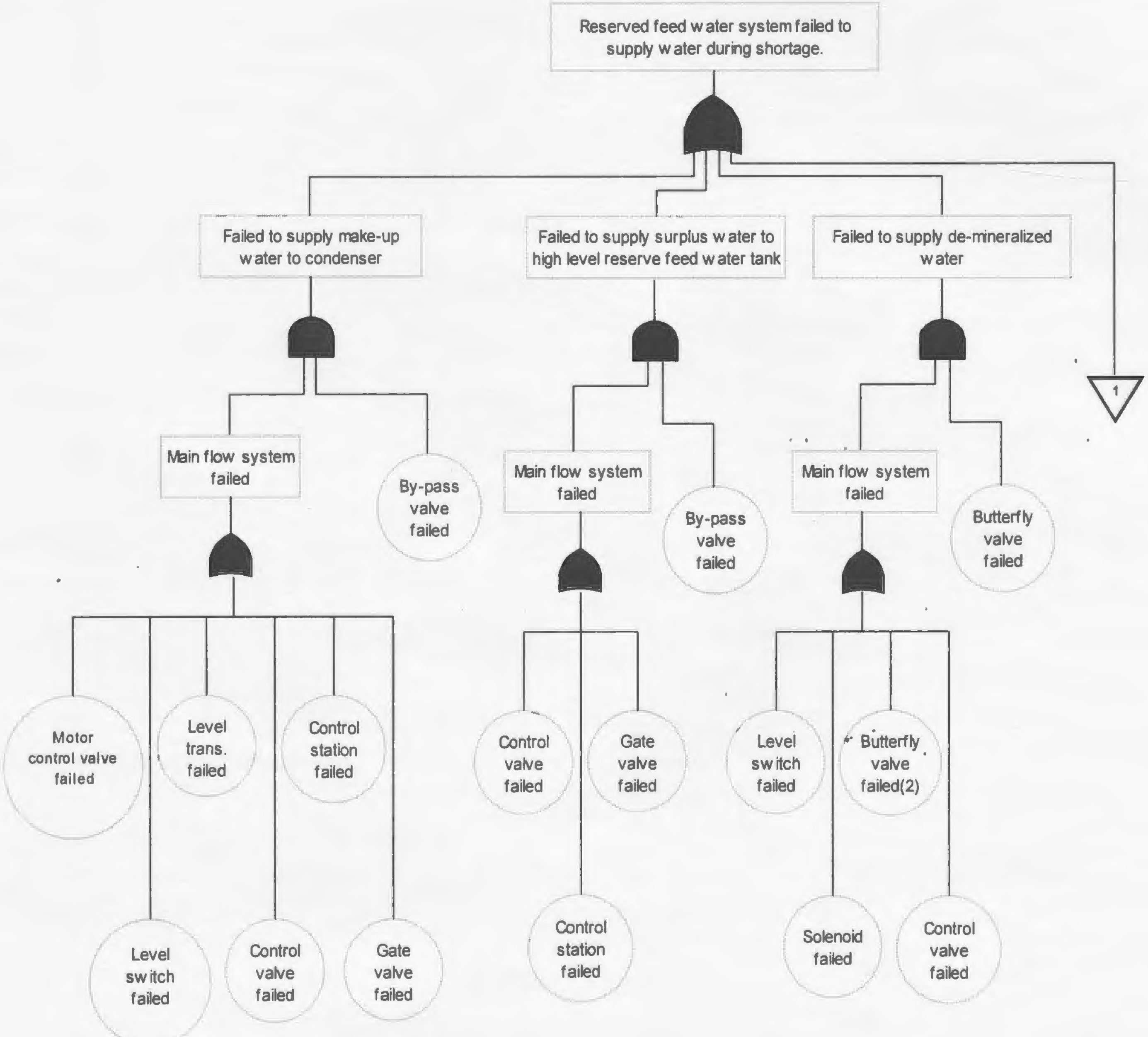
5.7.2 (c) LP heater #2



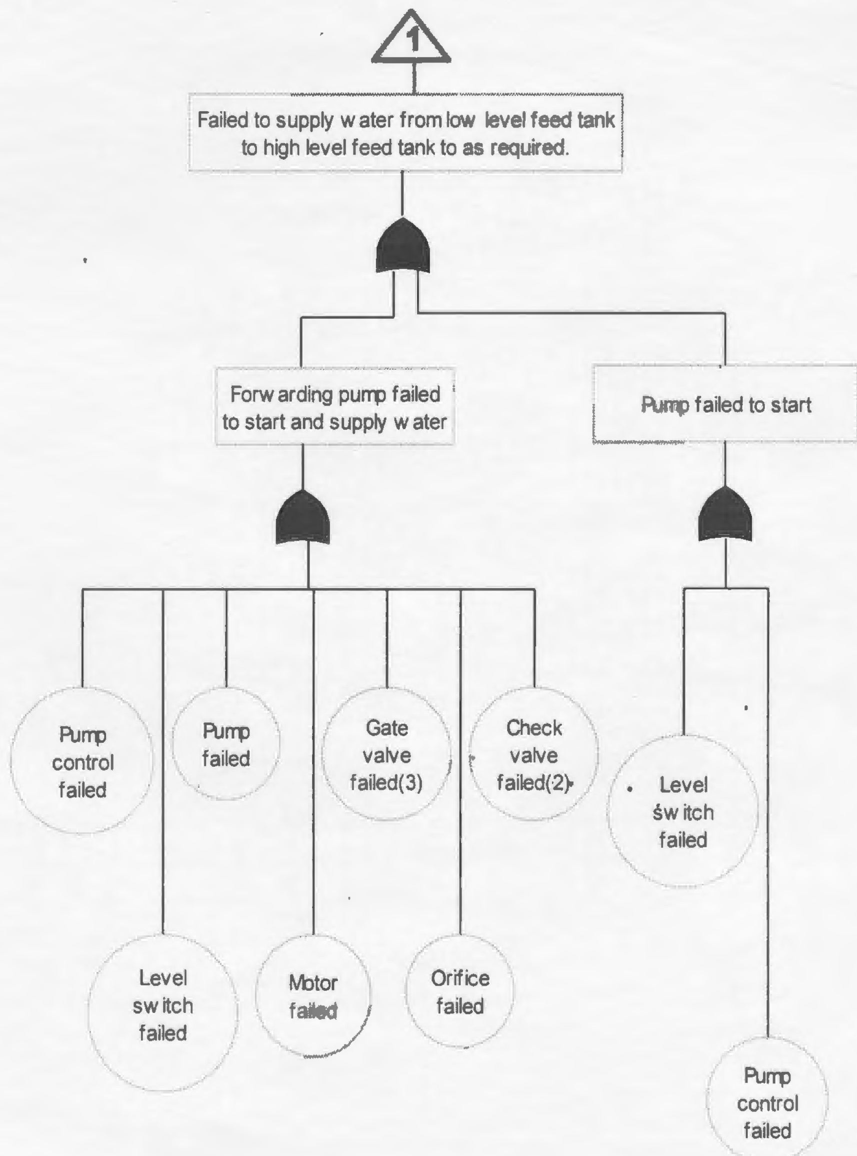
5.7 2(c) LP heater #2



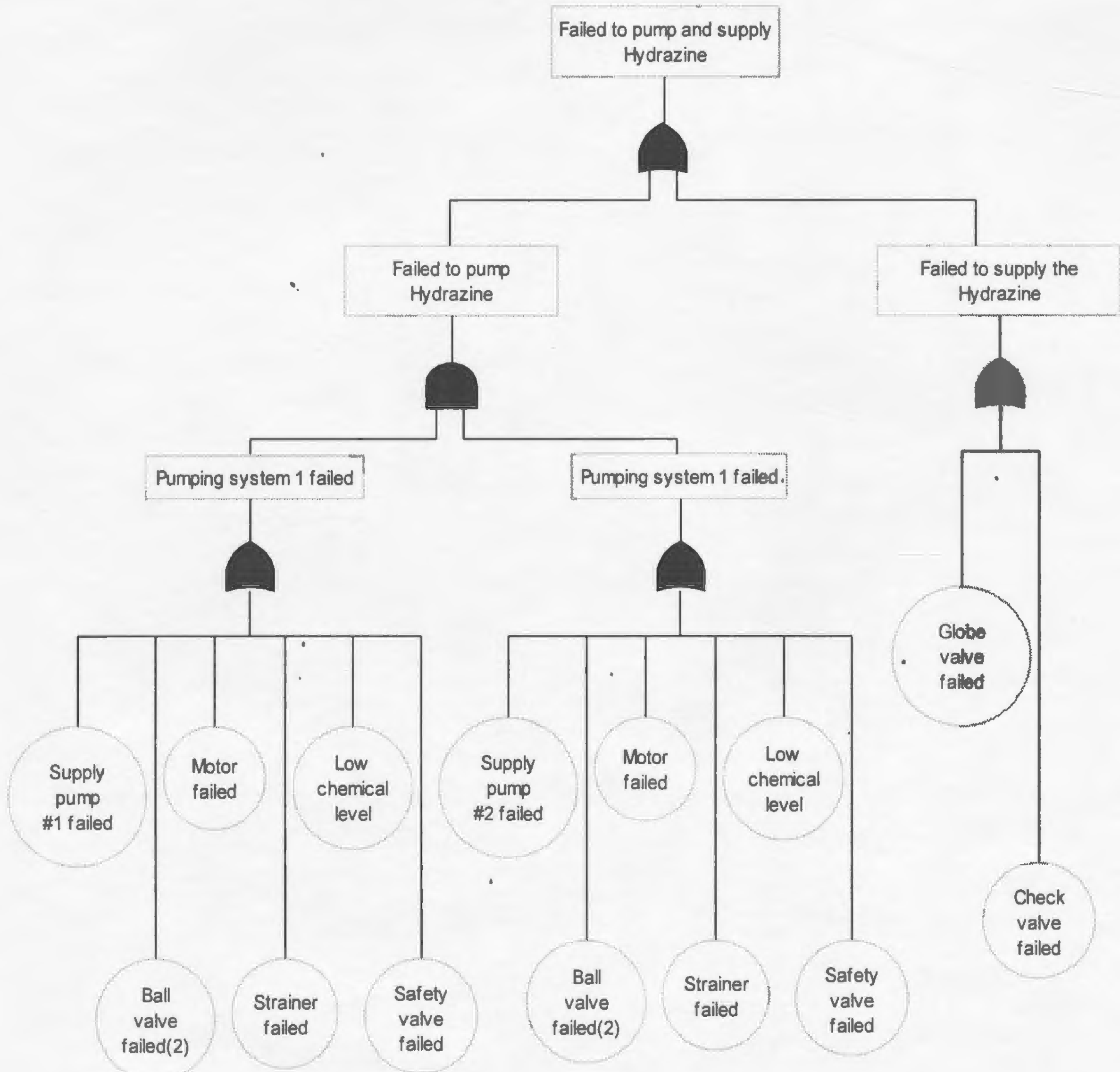
5.7.4 Reserve feed water system



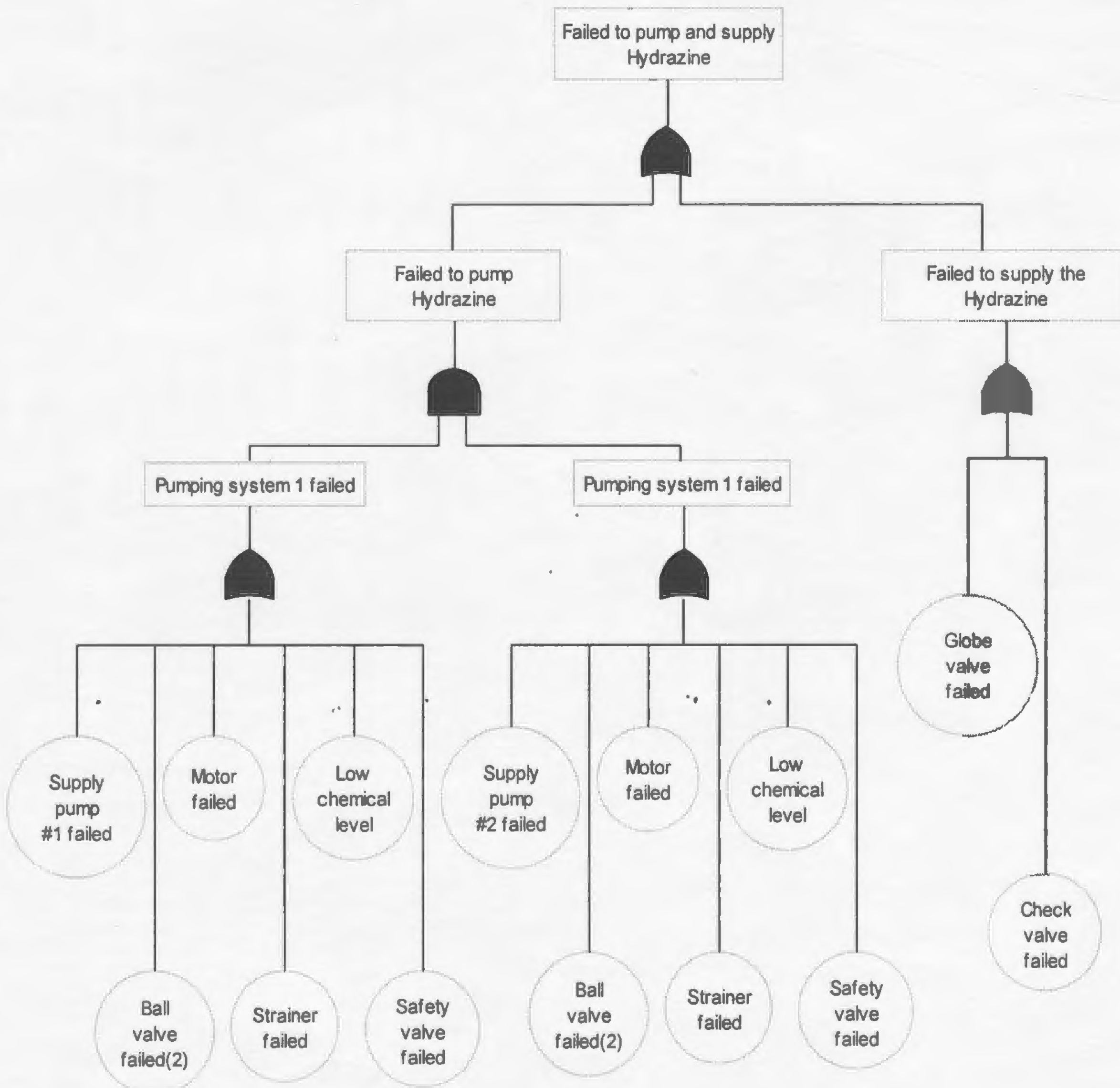
5.7.4 Reserve feed water system



5.7.5 Chemical supply system



5.7.5 (b) Chemical supply system



Appendix D – MTBF Confidence Limits

MTBF Confidence Limits

When a product's failure rate is considered constant, The Chi-Square distribution may be used to calculate confidence intervals around measured mean time between failures (MTBF), the total test time among all tested products divided by the number of failures. The calculation differs depending on whether the test data truncates on the last failure or at a time after the last failure.

	For time truncated tests	For failure truncated tests
One – sided confidence interval (MTBF lower limit)	$\dfrac{2T}{X^2(\alpha,2n+2)}$	$\dfrac{2T}{X^2(\alpha,2n)}$
Two sided Confidence Interval	$\dfrac{2T}{X^2(\alpha/2,2n+2)},\dfrac{2T}{X^2(1-\alpha/2,2n)}$	$\dfrac{2T}{X^2(\alpha/2,2n)},\dfrac{2T}{X^2(1-\alpha/2,2n)}$
MTBF limit	Lower Upper	Lower Upper

Where T is total test time

α is the acceptance risk of error (1 – desired confidence)

n is the number of failures observed

The following table is derived from the formulas:

d	Lower limit						Upper limit					
2	0.185	0.127	0.272	0.333	0.433	0.61	4.47	9.46	19.38	39.5	100	200
4	0.135	0.151	0.180	0.210	0.257	0.33	1.21	1.88	2.82	4.10	6.66	10.0
6	0.108	0.119	0.139	0.159	0.188	0.23	0.65	0.90	1.22	1.61	2.30	3.00
8	0.909	0.100	0.114	0.129	0.150	0.181	0.437	0.57	0.733	0.921	1.21	1.48

10	0.080	0.085	0.097	0.109	0.125	0.149	0.324	0.411	0.508	0.600	0.78	0.90
12	0.070	0.075	0.085	0.095	0.107	0.126	0.256	0.317	0.383	0.454	0.55	0.64
14	0.063	0.069	0.076	0.083	0.094	0.109	0.211	0.257	0.305	0.355	0.43	0.5
16	0.058	0.062	0.069	0.076	0.084	0.097	0.179	0.215	0.251	0.290	0.34	0.38
18	0.053	0.057	0.063	0.069	0.076	0.087	0.156	0.184	0.213	0.243	0.286	0.32
20	0.05	0.053	0 058	0.063	0.07	0.079	0.137	0.158	0.184	0.208	0.242	0.270
22	0.046	0.049	0.054	0.589	0.064	0.073	0.123	0.142	0.162	0.182	0.208	0.232
24	0.043	0.046	0.050	0.054	0.060	0.067	0.111	0.128	0.144	0.161	0.185	0.200
26	0.041	0.043	0.047	0.051	0.056	0.062	0.101	0.116	0.130	0.144	0.164	0.178
28	0.039	0.041	0.044	0.048	0.052	0.058	0.092	0.106	0.118	0.131	0.147	0.161
30	0.037	0.039	0.042	0.045	0.049	0.055	0.085	0.097	0.108	0.119	0.133	0.145
32	0.035	0.037	0.040	0.043	0.046	0.051	0.079	0.089	0.099	0.109	0.122	0.131
34	0.033	0.035	0.038	0.041	0.044	0.049	0.074	0.083	0.092	0.101	0.113	0.122
36	0.032	0.034	0.036	0.039	0.042	0.046	0.069	0.078	0.089	0.093	0.104	0.111
38	0.031	0.032	0.035	0.037	0.040	0.044	0.065	0.073	0.080	0.087	0.097	0.103
40	0.029	0.031	0.033	0.035	0.038	0.042	0.061	0.068	0.075	0.082	0.090	0.096

Notes: 1. Multiply value shown by total part hours to get MTBF figure in hours

2. d = 2 × (# of failures accumulated at test termination)

3. For the lower limit on tests truncated at a fixed time where the number of failures occurring is less than the total number of items placed on the test initially, use: d = 2× (# failures accumulated at test termination +1)

For example, the globe valve, N.O 23047-006 - style: packaged unit, POP: 20 (Page 3-549), the data given as 0/2.9170. The failures are 0.The hours are 2,917 x 10^^6 hours or 2917000 hours. Using the equation as shown in the PDF, the lower confidence interval is calculated as 2(2917000)/0.619 = 9424878.837 hours (MTBF). The failure rate is the inverse of the MTBF. This gives a failure rate of 0.106 failures/million hours. Similarly the upper value is 2(2917000)/4.47 = 0.766 failures/million hours.

Source: RAC Publication, CPE, Reliability Toolkit: Commercial Practices Edition.

Appendix E – Failure parameters and Probability Calculations

Failure Parameters

S.No	Major system /subsystem	Basic events	Failure parameters	Failure Probability in 20 years
5.1	Steam generator (SG)	Boiler	β–1.17, θ–50853.9 H	0.982
		Water walls	β–1.27, θ–57746.9 H	0.979
		Auxiliary steam supply	0.16/year	0.083
5.3	Fuel oil system	Fuel oil transfer system	0.16/year	0.959
		Fuel oil forwarding system	0.083/year	0.810
5.4 (a)	Turbine – Steam supply	Boiler stop valve	3.36E-06 H	0.445
		Main stop valve	0.1/year	0.865
		Motorized valve	3.36E-06 H	0.445
		Gate valve	1.50E-06 H	0.231
		Globe valve	2.76E-06 H	0.383
		Check valve	6.70E-06 H	0.691
		Combined re-heat valve	0.1/year	0.865
		Orifice	1.50E-07 H	0.026
		TIT	5.70E-06 H	0.632
		Steam and control system	0.083/year	0.810
		Control valve	5.73E–06 H	0.634
		PIT	3.50E-06 H	0.458
		Boiler control	β–1.17, θ–50853.9 H	0.867
		Combustion control	2.90E-05 H	0.994
		Fuel management and control	β–1.77, θ–52219.9 H	0.949
5.4 (b)	Turbine – Rotating system	Motor	8.60E-06 H	0.778
		Gear box	2.37E-06 H	0.340
		Governor	1.00E-06 H	0.161
		Globe valve	1.66E-05 H	0.945
		Intercept valve	9.00E-06 H	0.793
		Oil pump	1.00E-05 H	0.827
		Shaft packing*	0.1/year	0.865
		Journal bearing	0.083/year	0.810
		Thrust bearing	0.083/year	0.810
		Vibration detector	1.00E-08 H	0.002
		Oil deflector	3.20E-07 H	0.055
		Turbine instrumentation and control	0.16/year	0.810
		Moving blades*	1.14E-05 H	0.864
		Turbine rotors*	0.083/year	0.810
		Nozzle	1.14E-05 H	0.864
		Nozzle diaphragm	1.14E-05 H	0.864
		Coupling	9.90E-09 H	0.002
		Rotor position detector	1.00E-08 H	0.002
		Oil cooler	6.50E-07 H	0.108
5.5	Generator	Journal bearing failed	1.91E–07 H	0.033
		Oil deflector	1.60E-07 H	0.028
		Rotor**	1.00E-08 H	0.002

		Stator**	1.00E-08 H	0.002
		Generator brush	0.083/year	0.810
		Rectifier	2.60E-07 H	0.045
		Hydrogen seals**	1.00E-07 H	0.017
		Hydrogen cooling system	0.083/year	0.810
		Seal oil pump	3.90E–07 H	0.066
		Terminal box	1.00E-08 H	0.002
		Bushings	2.00E-08 H	0.003
		Control system	1.00E-07 H	0.017
5.6	Condenser	Condenser	1.50E-05 H	0.928
		Condenser tubes	β–1.51, θ–74607 H	0.830
5.7.2	Low pressure feed water system (LP)	Extraction pumps	4.21E-06 H	0.522
		Condensate make-up system	2.76E-06 H	0.959
5.7.3	High pressure feed water system (HP)	Feed water supply pump #1	β–1.18, θ–33925.7 H	0.952
		Gland seal system	0.083/year	0.810
		Gate valve failed	1.50E-06 H	0.231
		Feed water supply pump #2	β–1.34, θ–34845.6 H	0.966
		De-aerator	0.16/year	0.959
		HP heater #4	0.0001 H	0.990
		HP heater #5	β–2.9, θ–40607.4 H	0.998
		HP heater #6	0.08/year	0.798
		Feed water heater Ins.& Con.	0.08/year	0.798
		Motor control valve	3.36E-06 H	0.445
5.9	Instrument and service air system	Screw compressor	2.86E-06 H	0.394
		Compressor control	0.25/year	0.993
		Gate valve failed (3) F.O	4.50E-06 H	0.545
		Pressure switch	1.40E-07 H	0.024
		Filters failed (2)	1.40E-07 H	0.024
		Gate valve failed (4) F.O	6.00E-06 H	0.650
		Dryers failed (2)	6.00E-08 H	0.010
		Gate valve (2) F.O	3.00E-06 H	0.409
		Control valve	5.73E-06 H	0.634
5.1.1	SG - Furnace	Igniter	9.51E-06 H	0.811
		No air flow**	1.00E-08 H	0.002
		No light oil supply**	1.00E-08 H	0.002
		No steam flow**	1.00E-08 H	0.002
		Burners	β–1.65, θ–40215.4 H	0.999
		Retractable soot blowers*	0.083/year	0.810
		Rotary soot blowers*	0.083/year	0.810
		Accumulation of ash8	0.083/year	0.810
		Manual door	2.72E-06 H	0.379
		Refractory lining	5.00E-07 H	0.084
5.1.2	SG -Economizer	Economizer tubes	3.00E-07 H	0.051
		Supply header	1.00E-08 H	0.002
		Vent valve	5.70E-06 H	0.632
		Globe valve failed (3)	8.33E-06 H	0.768
		Less flue gas flow**	1.00E-08 H	0.002
		Excessive scaling**	1.14E-04 H	0.990
5.1.3	SG- Steam drum	Cyclone separator*	6.58E-06 H	0.684
		Water level high**	1.00E-08 H	0.002
		Feed water control system	β–2.21, θ–69743.6 H	0.996

		LIT	5.70E-06 H	0.632
		Steam drum	3.00E-06 H	0.409
		Down comer nozzle clogged	6.00E-06 H	0.650
		Worn gaskets and leakage	5.00E-07 H	0.084
		Safety valve	1.85E-06 H	0.277
		Faulty plate dryers	9.82E-06 H	0.821
		Liners broken	2.00E-06 H	0.296
5.1.4	SG- Super heater	Super heater	5.40E-07 H	0.090
		Super heater inlet header	1.00E-10 H	0.0001
		Safety valve	1.90E-05 H	0.964
		Steam and control system	9.51E-06 H	0.811
		Attemperator damaged**	1.00E-10 H	0.000
		Boiler control failed	β−1.17, θ−50853.9 H	0.982
		Nozzle	6.00E-06 H	0.650
		Globe valve failed (2)	5.52E-06 H	0.620
		By pass valve	2.76E-06 H	0.383
5.2.5	SG – Re-heater	Primary re-heater	1.74E-05 H	0.953
		Re-heater inlet header	1.00E-10 H	0.000
		Globe valve failed (4) F.O.	1.11E-05 H	0.856
		Angle valve failed. F.O	4.60E-06 H	0.553
		Control valve fails. F.O	5.73E-06 H	0.634
		Check valve fails F.O	2.30E-06 H	0.332
		Level switch f	0.22/year	0.988
		Blow down tank	3.00E-06 H	0.409
		Water seal failed	2.00E-07 H	0.034
		Globe valve failed (2) F.O	2.77E-06 H	0.384
5.1.8	Chemical supply system	Supply pump #1	4.78E-06 H	0.567
		Ball valve failed (2)	2.00E-06 H	0.296
		Strainer	3.70E-06 H	0.477
		Low chemical level**	3.00E-07 H	0.051
		Safety valve	1.85E-06 H	0.277
5 2 1 (a b)	Forced draft (FD) West and east	FD fan west	β−1.26, θ−52523.1 H	0.985
		FD an motor west	4.90E-05 H	0.783
		Furnace draft control	0.25/year	0.993
		Inlet guide van drive	2.80E-06 H	0.388
		Inlet dampers	6.70E-07 H	0.111
		Controller	0.25/year	0.993
		Timer	1.20E-06 H	0.190
		Relay	3.00E-08 H	0.005
		FD fan east	3.00E-05 H	0.995
		FD fan motor east	2.11E-05 H	0.975
5.2.2 (a, b)	Steam air heater West and east	Com. and gas control	2.77E-06 H	0.384
		Tubes	1.00E-08 H	0.002
		Dust collected over fins**	1.00E-08 H	0.002
5.2.3 (a, b)	Air pre-heater West and east (AH)	AH west fan	1.50E-05 H	0.928
		Reduced gas flow**	1.00E-07 H	0.017
		Gas in temperature low**	1.00E-07 H	0.017
		Reduced air flow**	1.00E-07 H	0.017
		Air in temperature low**	1.00E-07 H	0.017
		Broken seals	7.00E-07 H	0.115
		Plugged hot baskets*	1.00E-05 H	0.827

		Damaged ducts	2.17E-05 H	0.978
		AH east	2.00E-05 H	0.970
5.2.4 (a,b)	Air flow control system	FI failed	1.00E-08 H	0.002
		Flow control system	3.92E-06 H	0.497
5 2 5	Flue gas system	More slag built up*	0.083/year	0.810
		Incomplete combustion**	1.00E-07 H	0.017
		Low load in the generator*	10/day	1.000
		Oxygen analyzer*	1.00E-06 H	0.161
5.3.1	Heavy oil system	Fuel oil boosting system	β–2.18, θ–72895.4 H	0.927
		Temperature controller	0.1/year	0.865
		Control valve	5.73E-06 H	0.634
		Burner pipe and valves failed	0.16/year	0.959
		Burner management system	β–1.77, θ–52217.9 H	0.949
5.3.2	Light oil system	No oil in the tank**	1.00E-08 H	0.002
		Strainers blocked	3.70E-06 H	0.477
		Oil pump	4.78E-06 H	0.567
		Pump control	0.37/year	0.999
		Control system	β–1.77, θ–52217.9 H	0.949
		Piston valve	3.00E-08 H	0.005
5.3.3	Fuel additive system	Check valve failed	2.30E-06 H	0.332
		Reducer failed (2)	6.00E-08 H	0.010
		Pump failed	1.21E-05 H	0.879
		Pneumatic control system	0.37/year	0.999
5.6.3	Condenser - Vacuum	Butter fly 1 valve failed	1.00E-06 H	0.161
		Motorized valve failed	3.36E-06 H	0.445
		Motor failed	8.60E–06 H	0.778
		Vacuum pump failed	0.083/year	0.810
		Check valve failed	2.30E-06 H	0.332
		Heat exchanger failed	1.52E-06 H	0.234
		Gate valve failed	1.50E-06 H	0.231
		Globe valve failed	2.77E-06 H	0.384
		Level control valve failed	1.90E-05 H	0.964
		Gate valve failed	1.50E-06 H	0.231
		Globe valve failed	2.70E-06 H	0.377
5.6.1 (a)	Condenser – Cooling water supply	Pump failed	1.21E-05 H	0.880
		Relief valve	1.14E-05 H	0.864
		Motorized valve (2) F.O	6.72E–06 H	0.692
		Selector switch failed	0.22/year	0.988
		Screen blocked**	1.00E–07 H	0.017
5.6.1 (b)	Condenser – Screen wash system	Pump failed	1.21E-05	0.879
		Butterfly valve failed (3) F.O	3.00E–06 H	0.409
		Pressure switch	1.20E-07 H	0.021
		Pump control	0.37/year H	0.999
5.7.2	LP – water extraction	Butterfly valve	1.00E-06 H	0.161
		Hot well level low**	6.00E-08 H	0.010
		De-aerator level high**	6.00E-08 H	0.010
		Condensate extraction pump	1.21E-05 H	0.880
5.7.2 (a)	LP – Gland seal condenser	Tube	2.20E-07 H	0.038
		Excessive scaling***	1.00E-07 H	0.017
5.7.2 (b)	LP heater #1&2	Orifice	1.50E-07 H	0.026
		Pneumatic actuator	1.21E-05 H	0.880

		Control relay	0.01/year	0.181
		Solenoid valve	4.60E-06 H	0.553
		Level switch	8.00E-08 H	0.014
		Drain pump	8.43E-06 H	0.772
		Level switch	8.00E-08 H	0.014
		Low water level**	1.00E-08 H	0.002
5.8	Water de-mineralization system	Clarifier*	1.00E-06 H	0.161
		Mono-valve filters*	8.00E-08 H	0.014
		Cation exchanger*	2.00E-06 H	0.296
		Anion exchanger*	2.00E-06 H	0.296
		Mixed bed exchanger*	2.00E-06 H	0.296

* Failure parameters are fixed in consultation with plant officials

** Failure parameters are fixed based on failure rate data for machinery components from field statistics (subjective)

H – hours.

Appendix F – Excel sheet for repair cost estimate

Maintenance cost-Repair cost estimate

Trade		Men	Days	Hrs/day	Total Hrs.	Rate in Dollars	Total
BM	General Foreman		0	0	0	$46.21	0
BM	Foreman	0	4	2	0	$44.90	0
BM	Fitter/welder	0	4	12	0	$41.26	0
BM	Apprentice 3	0	2	12	0	$38.04	0
BM	Apprentice 2	0			0	$32.81	0
BM	Apprentice 1	0			0	$27.64	0
BM	Helper	0	5	12	0	$38.04	0
		0			0		0
PF	Foreman	0	5	12	0	$45.49	0
PF	Welder/Journeyman	0	5	12	0	$42.64	0
					0		0
MW	Foreman	0	1	500	10	$41.47	414.7
MW	Welder/Journeyman	0	1	3000	20	$40.22	804.4
MW	Apprentice	0	4	8	0	$38.60	0
Laborers	Journey	0	0.76	8	0	$34.64	0
					0		
	Instrumentcian	1	1	12	12	$25.00	$300.00
	Electrician	1	1	12	12	$25.00	$300.00
Total hours/Labor cost					54		$1,819.10
Small tools						$3.00	$162.00
							$1,981.10

Appendix G – Risk anlysis results

Risk analysis results

S.No	Major system	Subsystems/ Components	Maintenance cost		Production lost cost	Total cost	Scenario consequence	Probability of occurrence for the scenario (20 years)	Risk factor in $ for 20 years	Risk Index	RAnk
			Repair cost	Spare parts cost							
5.	Power plant	Steam generator	30,481	30,000	3,618,000	3,678,481	3,678,481	0.9999	3,678,113		
		Air and flue gas system	3,967	30,000	2,068,056	2,102,023					
		Fuel oil system	6,804	10,000	1,093,770	1,110,574					
		Turbine steam supply	6,804	10,000	1,093,770	1,110.574					
		Turbine rotating system	9,033	2,500	290,520	302,053					
		Generator	94,100	1,500,000	39,960	1,634,060					
		Condenser	3,455	0.00	871,290	874,745					
		LP feed water system	1639	500	224030	226,169					
		HP feed water system	2624	15000	2461218	2,478,842					
		Instrument and service air system	5,249	20,000	0.00	25,249					
5.1	Steam generator	Boiler	30,481	30,000	3,618,000	3,678,481	3,678,481	0.9989	3,674,434	1.837	1
		Furnace	5,487	3,500	925,965	934,952					
		Economizer	126,823	0.00	0.00	126,823					
		Steam drum	200	2,956	71,235	74,391					
		Super heater	6,804	10,000	1,093,770	1,110,574					
		Re-heater	6,804	10,000	1,093,770	1,110,574					
		Water walls	0.00	17,747	1,969,987	1,987,734					
		Blow down system	15,963	12,000	5,400	33,363					
		Chemical supply system	1,034	2,100	180	3,314					
		Auxiliary steam supply	5,945	4,500	779,895	790,340					
5.2	Air and flue gas system	Forced draft system west	3967	25000	1309960	1,338,927	2,102,023	0.9914	2,083,945	1.042	3
		Forced draft system east	3967	25000	1431216	1,460,183					
		Steam air heater system west	8295	10000	95400	113,695					
		Steam air heater system east	8295	10000	95400	113,695					
		Air pre-heater system west	3967	30000	244451	278,418					
		Air pre-heater system east	3967	30000	2068056	2,102,023					

		Air flow control west, east	8295	10000	95400	113,695					
		Flue gas system	126823	0.00	0.00	126,823					
5.3	Fuel oil system	Fuel oil transfer system*	14518	1000	28417	43,935	1110574	0.9866	1,095,692	0.548	6
		Fuel oil forwarding system*	17377	25000	46170	88,547					
		Heavy oil system	6804	10000	1093770	1,110,574					
		Light oil system	860	10800	0.00	11,660					
		Pipe	850	1000	2160	4,010					
		Fuel additive system	890	10800	0.00	11,690					
5.4 (a)	Turbine steam supply	Boiler stop valve	2870	1800	3240	7,910	1110574	0.9999	1,110,462	0.555	5
		Main stop valve	11643	3000	12960	27,603					
		Motorized valve	1526	1000	2160	4,686					
		Gate valve	1332	110	2160	3,602					
		Globe valve	1332	190	2160	3,682					
		Check valve	1526	45	2160	3,731					
		Combined re-heat valve *	14150	3000	15120	32,270					
		Orifice	1332	500	1080	2,912					
		TIT	112	71	1080	1,263					
		Steam and control system	100	200	256	556					
		Control valve	6340	15000	7560	28,900					
		PIT	112	2217	1080	3,409					
		Boiler control failed	6804	10000	1093770	1,110,574					
5.4 (b)	Turbine rotating system	Motor	752	1351	2160	4,263	302053	0.9999	302,022	0.151	8
		Gear box	3764	476	6480	10,720					
		Governor	2981	1000	2160	6,141					
		Globe valve	14150	12600	15120	41,870					
		Intercept valve	14150	18000	15120	47,270					
		Motor	1396	1947	2160	5,503					
		Oil pump	1396	901	6480	8,777					
		Oil pump	1396	901	6480	8,777					
		Drive	4653	737	6480	11,870					
		Shaft packing	10229	30000	5400	45,629					
		Journal bearing	9033	2500	290520	302,053					
		Thrust bearing	3900	22511	7992	34,403					
		Vibration detector	1077	591	0.00	1,668					
		Oil deflector	1505	6000	5400	12,905					

		Turbine instrumentation and control	423	500	101587	102,510					
		Moving blades*	18776	120000	37800	176,576					
		Turbine rotors*	1309	1000	23220	25,529					
		Nozzle*	16943	24000	37800	78,743					
		Nozzle diaphragm*	9163	37500	37800	84,463					
		Coupling*	1309	75000	43200	119,509					
		Rotor position detector*	1077	233	1080	2,390					
		Oil cooler*	1176	935	2160	4,271					
5.5	Generator	Journal bearing*	3011	2937	7560	13,508	1634060	0.9780	1,598,110	0.799	4
		Oil deflector*	4140	2000	7560	13,700					
		Rotor*	75280	1000000	37800	1,113,080					
		Stator*	94100	1500000	39960	1,634,060					
		Shaft seal	2045	5000	1080	8,125					
		Generator brush	632	702	360	1,694					
		Rectifier	448	1000	360	1,808					
		Hydrogen seals*	5646	20000	10800	36,446					
		Hydrogen cooling system	7528	10000	493762	511,290					
		Seal oil pump	1396	979	6480	8,855					
		Motor*	752	848	0.00	1,600					
		Terminal box	752	2000	3240	5,992					
		Bushings	3764	10000	7560	21,324					
		Control system	1981	350	540	2,871					
5.6	Condenser	Vacuum system	678	18725	540	19,943	874745	0.9939	869,409	0.435	7
		Cooling water supply system	2680	8000	2160	12,840					
		Screen wash system	2680	10000	0.00	12,680					
		Condenser back wash system	1533	3600	0.00	5,133					
		Condenser	1786	2000	291269	295,055					
		Condenser tubes	3455	0.00	871290	874,745					
		Vent valve	100	15.00	0.00	115					
5.7.2	Low pressure feed water system	Extraction pumping system	2624	10800	2160	15,584	286584	0.9995	286,441	0.143	9
		Gland seal condenser	2214	4000	2160	8,374					
		LP heater #1	2214	4000	2160	8,374					
		LP heater #2	2214	4000	2160	8,374					
		Reserve feed water system	691	6502.	0.00	7,193					
		Water de-mineralizing system	691	6502.	0.00	7,193					
		Hydrazine supply system	691	1517	180	2,388					

		Morphoilne system	691	1517	180	2,388					
		Condensate make-up	0.00	1000	224030	225,030					
		Condensate make-up system ins&con	1639	500	284445	286,584					
5.7.3	High pressure feed water system	Feed auxiliaries	15371	5250	1143585	1,164,206	2478842	0.9999	2,478,594	1.239	2
		Feed water supply pump #1	2624	15000	2461218	2,478,842					
		Gland sealing	150	300	2328	2,778					
		Motor failed	2624	75000	0.00	77,624					
		Gate valve	1533	1600	2160	5,293					
		Feed water supply pump #2	2624	15000	574762	592,386					
		LP heater #4	413	2500	61875	64,788					
		LP heater #5	1654	5000	222750	229,404					
		LP heater #6	1526	1500	31842	34,868					
		Feed water heater Ins.& Con.	2956	200	71235	74,391					
		De-aerator	499	2000	123322	125,821					
		Feed water piping and support	61230	10000	1620888	1,692,118					
		Feed water heater ins and control	210	200	76545	76,955					
5.9	Instrument air	Screw compressor motor	5249	9112	0.00	14,361	25249	0.9650	24,365	0.012	10
		Screw compressor	5249	20000	0.00	25,249					
		Compressor control	224	832	0.00	1,056					
		Gate valve failed	1200	1950	0.00	3,150					
		Pressure switch failed	112	82	0.00	194					
		Check valve failed	413	1391	0.00	1,804					
		Filters	200	106	0.00	306					
		Gate valve failed	1600	930	0.00	2,530					
		Dryers failed	200	1700	0.00	1,900					
		Gate valve	816	468	0.00	1,284					
		Pressure switch	112	82	0.00	194					
		Check valve	413	274	0.00	687					
		Control valve	1556	1500	0.00	3,056					
5.1.1	Furnace	Igniter fails	5281	15000	311917	332,198	934952	0.9825	918,590	0.459	7
		Burners	5487	3500	925965	934,95					
		Retractable soot blowers*	6218	2500	0.00	8,718					
		Rotary soot blowers*	4625	2000	0.00	6,625					
		Accumulation of ash	0.00	126823.	0.00	126,823					
		Manual door*	1733	500	2160	4,393					
		Refractory lining*	123	2000	3240	5,363					
5.1.2	Economizer	Economizer tubes	14423	15000	5400	34,823	126823	0.6291	79,784	0.039	14

		Supply header	13758	10000	5400	29,158					
		Vent valve	1722	26	5400	7,148					
		Globe valve failed	2131	130	5400	7,661					
		Excessive scaling	0.00	126823	0.00	126,823					
5.1.3	Steam drum	Cyclone separator	1000	18686	5400	25,086	74391	0.9855	73,312	0.036	15
		Feed water control system	200	2956	71235	74,391					
		LIT	4809	978	5400	11,187					
		Steam drum	25060	10000	5400	40,460					
		Down comer nozzle	2839	0.00	5400	8,239					
		Worn gaskets and leakage	2072	750	1080	3,902					
		Safety valve	1393	3000	1080	5,473					
		Faulty plate dryers	18686	1000	5400	25,086					
		Liners broken	18686	1000	5400	25,086					
5.1.4	Super heater	SS heater	14423	20000	5400	39,823	1110574	0.9925	1,102,244	0.551	6
		PS outlet header	6548	10000	3240	19,788					
		Safety valve	1091	3000	303885	307,976					
		TIT	177	71	3240	3,488					
		Steam and control system	50	200	88020	88,270					
		Attemperator	6548	5000	3240	14,788					
		Control valve	1364	1500	3240	6,104					
		PIT	177	2217	3240	5,634					
		Boiler control	6804	10000	1093770	1,110,574					
		Nozzle	2855	2624	3240	8,719					
		Globe valve	2131	341	4320	6,792					
		By pass valve	1065	341	4320	5,727					
5.1.5	Re-heater	Primary re-heater	14423	20000	271701	306,124	1110574	0.9970	1,107,242	0.553	5
		Re-heater inlet header	6548	10000	3240	19,788					
		Control system	6804	10000	1093770	1,110,574					
		Control valve	1364	1500	3240	6,104					
		Nozzle	2855	2624	3240	8,719					
		Globe valve	2131	682	4320	7,133					
		Boiler control	6804	10000	1093770	1,110,574					
5.1.6	Blow down system	Globe valve	3196	130	2160	5,486	33363	0.9733	32,472	0.016	16
		Angle valve	1538	144	2160	3,842					
		Control valve	1538	2100	2160	5,798					
		Check valve	1538	692	2160	4,390					
		Level switch	177	10	2160	2,347					
		By pass valve	1598	140	2160	3,898					
		Blow down tank	15963	12000	5400	33,363					
		Water seal	1598	350	3240	5,188					
5.1.8	Chemical supply system M,A,H	Supply pump #1	691	1517	180	2,388	2388	0.9786	2,337	0.001	29
		Ball valve	1034	110	180	1,324					

		Motor	691	848	180	1,719					
		Strainer	790	850	180	1,820					
		Safety valve	1034	111	180	1,325					
		Globe valve	1034	130	180	1,344					
		Check valve	1034	47	180	1,261					
5.2.1 (a, b)	Forced draft fan west and east	FD fan west	3967	25000	1309960	1,338,927	1338927	0.9962	1,333,839	0.666	3
		FD fan motor west	3967	52514	96425	152,906					
		Furnace draft control	5463	5000	175500	185,963					
		Inlet guide van drive	1318	592	270	2,180					
		Combustion control	8295	10000	95400	113,695					
		Inlet dampers	2696	4000	270	6,966					
		Inlet damper drive	1318	592	270	2,180					
		Timer	224	471	0.00	695					
		Relay	224	180	0.00	404					
		FD fan east	3967	25000	1431216	1,460,183	1460183	0.9969	1,455,656	0.727	2
		FD fan motor	3967	52514	160706	217,187					
5.2.2 (a, b)	Steam air heater west and east	Globe valve	1580	384	180	2,144	113695	0.9557	108,658	0.054	12
		Control valve	1278	1000	180	2,458					
		Com. and gas control	8295	10000	95400	113,695					
		Globe valve failed	790	192	180	1,162					
		Gate valve	790	180	180	1,150					
		Tubes damaged	2838	627	1080	4,545					
		Dust collected over fins	4215	0.00	8064	12,279					
5.2.3 (a,b)	Air pre heater west and east	AH west	3967	30000	244451	278,418	278418	0.9724	270,733	0.013	8
		Drive motor	3967	2136	244451	250,554					
		Air in temp. low	0.00	0.00	0.00	0.00					
		Broken seals	12647	2777	15120	30,544					
		Plugged hot baskets	12647	0.00	15120	27,767					
		Ducts	2062	600	180	2,842					
		AH east	3967	30000	2068056	2,102,023	2102023	0.9729	2,045,058	1.022	1
		Drive motor	3967	2136	244451	250,554					
5.2.4 (a,b)	Air flow control system	FIT	224	1054	0.00	1,278	113695	0.9568	108,783	0.054	10
		FI failed	224	1889	0.00	2,113					
		FCS	224	1889	0.00	2,113					
		Combustion control	8295	10000	95400	113,695					
3.9	Flue gas system	More slag built up	1268230	0.00	0.00	126,823	126823	0.9720	123,271	0.061	9
		Oxygen analyzer	224	2103	0.00	2,327					
		Ducts	2062	600	180	2,842					
		Lining	4000	2000	5400	11,400					
5.3.1	Heavy oil system	LIT	112	978.	0.00	1,090	1110574	0.9989	1,109,352	0.554	4

		Control valve	1556	15000	2160	18,716					
		By pass valve	666	1842	2160	4,668					
		Gate valve	666	1842	2160	4,668					
		Gate valve	1332	1842	2160	5,334					
		Fuel oil boosting system	6677	5000	364500	376,177					
		Temperature controller	112	53.	0.00	165					
		Control valve	890	15000	2160	18,050					
		Combustion control	8295	10000	95400	113,695					
		Burner pipe and valves*	20774	15000	1003275	1,039,049					
		Burner management	4324	4000	92745	101,069					
		Boiler master control failed	6804	10000	1093770	1,110,574					
5.3.2	Light oil system	Gate valve	666	0.00	0.00	666	11660	0.9921	11,567	0.005	21
		Strainers	1419	110	0.00	1,529					
		Oil pump	860	10800	0.00	11,660					
		Pump control	224	703	0.00	927					
		Motor failed	860	3719	0.00	4,579					
		Control valve	890	3000	0.00	3,890					
		Globe valve	666	130	0.00	796					
		Piston valve	666	47	0.00	713					
5.3.3	Fuel additive system	Globe valve	666	132	0.00	798	11690	0.9201	10,755	0.005	22
		Check valve	666	45	0.00	711					
		Reducer failed	450	93	0.00	543					
		Piston valve	666	102	0.00	768					
		Pump	890	10800	0.00	11,690					
		Pneumatic control system	224	161	0.00	385					
		Motor	890	750	0.00	1,640					
5.6.3	Vacuum	Butter fly valve	1533	458	540	2,531	19943	0.9942	19,827.33	0.009	17
		Motorized valve	1533	700.	540	2,773					
		Motor	678	6000	540	7,218					
		Vacuum pump	678	18725	540	19,943					
		Check valve	678	467	540	1,685					
		Heat exchanger	947	1229	540	2,716					
		Gate valve	678	432	540	1,650					
		Level control valve	865	350	540	1,755					
		Gate valve	678	47	540	1,265					
		Globe valve	678	341	540	1,559					
5.6.1	Cooling water supply system	Pump	2680	8000	2160	12,840	12840	0.9990	12,827	0.006	19
		Motor	2680	7500.	2160	12,340					
		Relief valve	678	750	2160	3,588					
		Motorized valve	2680	1500	2160	6,340					
		Timer	112	2078	0.00	2,190					
		Selector switch	112	447	0.00	559					

		Screen block	2497	0.00	1080	3,577					
5.6.1 (b)	Screen wash system	Pump	2680	10000	0.00	12,680	12680	0.9951	12,617	0.006	20
		Motor	2680	3719	0.00	6,399					
		Butterfly valve	2000	205	0.00	2,205					
		Gate valve	1300	558	0.00	1,858					
		Check valve	678	801	0.00	1,479					
		Timer	112	2078	0.00	2,190					
		Pressure switch	112	276	0.00	388					
		Pump control*	224	832	0.00	1,056					
5.7.2	Water extraction	Butterfly valve	2761	1200	2160	6,121	15584	0.9865	15,374	0.007	18
		Motor	2624	7500	2160	12,284					
		Gate valve	778.	7500	1080	9,358					
		Pump control	224	832	1080	2,136					
		Check valve	778	801	1080	2,659					
		Condensate extraction pump	2624	10800	2160	15,584					
5.7.2 (a)	Gland seal condenser	Check valve	413	393	1080	1,886	8374	0.8556	7,164	0.003	26
		Globe valve	413	341	1080	1,835					
		Orifice	413	500	1080	1,993					
		Butter fly valve	2870	2000	1080	5,950					
		Nozzle	2855	220	1080	4,155.					
		Globe valve	413	149	1080	1,642					
		Tube	2214	4000	2160	8,374					
		Cleaning the tubes	2408	0.00	0.00	2,408					
5.7.2 (b,c)	Low pressure feed water heater #1&2	Orifice	413	500	1080	1,993	8374	0.9998	8,372	0.004	23
		Globe valve	413	341	1080	1,835					
		Motor control valve	413.	1500	1080	2,993					
		Tubes	2214	4000	2160	8,374					
		Excessive scaling	2408	0.00	4320	6,728					
		Butterfly valve	2870	2800	1080	6,750					
		Nozzle	2855	107	2160	5,122					
		Check valve	2870	3600	1080	7,550					
		Pneumatic actuator	250	59	0.00	309					
		Control relay	224	193 .	0.00	417					
		Solenoid valve	1033	133	0.00	1,166					
		Motor	752	1351	0.00	2,103					
		Drain pump	752	4000	0.00	4,752					
5.7.4	Reserve feed water system	Motor control valve	1526	1500	1080	4,106	7193	0.9998	7,191	0.003	25
		Gate valve	666	649	1080	2,395					
		Control station	224	1954	0.00	2,178					

		Solenoid	224	169	0.00	393					
		Pump control	224	832	0.00	1,056					
		Pump	699	6502	0.00	7,193					
		Motor	691	3150	0.00	3,841					
		Orifice	413	500	1080	1,993					
		Check valve	413	637	0.00	1,050					
5.8	Water de-mineralization system	Clarifier	1204	1000	2160	4,364	7193	0.9585	6,894	0.003	27
		Mono-valve filters	1204	1000	2160	4,364					
		Cation exchanger	1204	1000	2160	4,364					
		Anion exchanger	1204	1000	2160	4,364					
		Mixed bed exchanger	1204	1000	2160	4,364					
		Gate valve	413	558	0.00	971					
		Butterfly valve	413	111	0.00	524					
		Pump	691	6502	0.00	7,193					
		Pressure switch	224	82	0.00	306					
		Motor	691	3150	0.00	3,841					
		Check valve	413	637	0.00	1,050					

M- Morpholine, A-Ammonia, H- Hydrazine

* Details of the cost not available in plant records, estimated upon interviewing plant officials.

Appendix H – Matlab program for reverse probability analysis

High pressure feed water system

```
function[F]=hpf(x)
a18=0.001-0.0001*x;
a17=0.001-0.0001*x;
a16=0.93-0.0763*x;
a15=0.23-0.0189*x
a14=0.95-0.0780*x,
a13=0.79-0.0648*x;
a12=0.79-0.0648*x;
a11=0.99-0.0813*x;
a10=0.99-0.0813*x;
a9=0.87-0.0714*x;
a8=0.81-0.0665*x;
a7=0.23-0.0189*x;
a6=0.95-0.0780*x;
a5=0.87-0.0714*x;
a4=0.23-0.0189*x;
a3=0.81-0.0665*x;
a2=0.95-0.0780*x;
a1=0.79-0.0648*x;
p1=(1-(1-a1)*(1-a2)*(1-a3)*(1-a4));
p2=(1-(1-a5)*(1-a6)*(1-a7)*(1-a8));
p3=(1-(1-p1)*(1-p2));
p4=(1-(1-a10)*(1-a11)*(1-a12)*(1-a13));
p5=(1-(1-a14)*(1-a15)*(1-a16));
p6=a17*a18;
F=(1-(1-p1)*(1-p2)*(1-p4)*(1-p5)*(1-p6)*(1-a1))-0.8;

x=fzero(@hpf, 0)

x =

   10.6507

clear all;
close all;
```

```
fid1=fopen('hpff.dat','w');
%y=-10:.001:10;
%for i=1:length(y)
%x=y(i)
x=10.6507;
a18=0.001;
a17=0.001;
a16=0.93-0.0763*x;
a15=0.23-0.0189*x;
a14=0.95-0.0780*x;
a13=0.79-0.0648*x;
a12=0.79-0.0648*x;
a11=0.99-0.0813*x;
a10=0.99-0.0813*x;
a9=0.87-0.0714*x;
a8=0.81-0.0665*x;
a7=0.23-0.0189*x;
a6=0.95-0.0780*x;
a5=0.87-0.0714*x;
a4=0.23-0.0189*x;
a3=0.81-0.0665*x;
a2=0.95-0.0780*x;
a1=0.79-0.0648*x;
p1=(1-(1-a1)*(1-a2)*(1-a3)*(1-a4));
p2=(1-(1-a5)*(1-a6)*(1-a7)*(1-a8));
p3=(1-(1-p1)*(1-p2));
p4=(1-(1-a10)*(1-a11)*(1-a12)*(1-a13));
p5=(1-(1-a14)*(1-a15)*(1-a16));
p6=a17*a18;
F=(1-(1-p1)*(1-p2)*(1-p4)*(1-p5)*(1-p6)*(1-a1))-0.8;
fprintf(fid1, 'a1 = %7.6f \n', a1);
fprintf(fid1, 'a2 = %7.6f \n', a2);
fprintf(fid1, 'a3 = %7.6f \n', a3);
fprintf(fid1, 'a4 = %7.6f \n', a4);
fprintf(fid1, 'a5 = %7.6f \n', a5);
fprintf(fid1, 'a6 = %7.6f \n', a6);
fprintf(fid1, 'a7 = %7.6f \n', a7);
```

```
fprintf(fid1, 'a8 = %7.6f \n', a8);
fprintf(fid1, 'a9 = %7.6f \n', a9);
fprintf(fid1, 'a10 = %7.6f \n', a10);
fprintf(fid1, 'a11 = %7.6f \n', a11);
fprintf(fid1, 'a12 = %7.6f \n', a12);
fprintf(fid1, 'a13 = %7.6f \n', a13);
fprintf(fid1, 'a14 = %7.6f \n', a14);
fprintf(fid1, 'a15 = %7.6f \n', a15);
fprintf(fid1, 'a16 = %7.6f \n', a16);
fprintf(fid1, 'a17 = %7.6f \n', a17);
fprintf(fid1, 'a18 = %7.6f \n', a18);
fprintf(fid1, 'x =%7.6f \n', x);
fprintf(fid1, 'F =%7.6f \n', F);
fclose(fid1)
%end
%plot(y,F);
```